UNIVERSITY OF CAMBRIDGE
Faculty of Economics

Cambridge Working Papers in Economics

Cambridge Working Papers in Economics: 2039

MERCHANT UTILITIES AND BOUNDARIES OF THE FIRM: VERTICAL INTEGRATION IN ENERGY-ONLY MARKETS

Paul Simshauser

12 May 2020

A central feature of electricity market reforms involved restructuring monopoly utilities. In the Generation segment, policies promoting restructuring and competition could not be faulted on the grounds of scale economies. But the partitioning of Generation from Retail received little focus. When proposals for industry restructuring emerged, multi-stage scope economies should have been of unquestionable interest but surprisingly little empirical evidence existed. Governments proceeded in the 1990s with an industrial organisation blueprint which separated Generation from Networks, and combined Retail with Distribution Networks. A second wave of industrial organisation was orchestrated by capital markets in the 2000s, splitting Retail from Distribution, and merging Retail with Generation. Many policymakers and regulators view the practice of vertical integration in a neoclassical sense; presenting risks of withholding capacity, increasing prices, raising barriers to entry, non-integrated rival foreclosure and damaging consumer welfare. But the weight of theoretical and empirical evidence points to the contrary, with transaction costs featuring prominently. In this article, a Generator and Retailer are simulated over 15 years of trade in Australia's National Electricity Market as stand-alone businesses, and then as a merged entity. A comparison of the Sum-Of-The-Parts with the Vertical Firm reveals non-trivial transaction costs and multi-stage economies of integration – the Vertical Firm reduces costs by 17% and volatility of earnings by 83%, which produces a 26% improvement in credit quality and lifts statutory profits by 34% holding prices and volumes constant.

Merchant utilities and boundaries of the firm: vertical integration in energy-only markets

EPRG Working Paper 2008

Cambridge Working Paper in Economics 2039

Paul Simshauser

Abstract A central feature of electricity market reforms involved restructuring monopoly utilities. In the Generation segment, policies promoting restructuring and competition could not be faulted on the grounds of scale economies. But the partitioning of Generation from Retail received little focus. When proposals for industry restructuring emerged, multi-stage scope economies should have been of unquestionable interest but surprisingly little empirical evidence existed. Governments proceeded in the 1990s with an industrial organisation blueprint which separated Generation from Networks, and combined Retail with Distribution Networks. A second wave of industrial organisation was orchestrated by capital markets in the 2000s, splitting Retail from Distribution, and merging Retail with Generation. Many policymakers and regulators view the practice of vertical integration in a neoclassical sense; presenting risks of withholding capacity, increasing prices, raising barriers to entry, non-integrated rival foreclosure and damaging consumer welfare. But the weight of theoretical and empirical evidence points to the contrary, with transaction costs featuring prominently. In this article, a Generator and Retailer are simulated over 15 years of trade in Australia's National Electricity Market as stand-alone businesses, and then as a merged entity. A comparison of the Sum-Of-The-Parts with the Vertical Firm reveals non-trivial transaction costs and multi-stage economies of integration – the Vertical Firm reduces costs by 17% and volatility of earnings by 83%, which produces a 26% improvement in credit quality and lifts statutory profits by 34% holding prices and volumes constant.

Keywords vertical integration, electricity markets, energy-only markets, transaction costs, credit ratings

JEL Classification D23, D24, D25, G34, L94

Contact p.simshauser@griffith.edu.au
Publication May 2020

Merchant utilities and boundaries of the firm: vertical integration in energy-only markets

Paul Simshauser♣♠
May 2020

Abstract
A central feature of electricity market reforms involved restructuring monopoly utilities. In the Generation segment, policies promoting restructuring and competition could not be faulted on the grounds of scale economies. But the partitioning of Generation from Retail received little focus. When proposals for industry restructuring emerged, multi-stage scope economies should have been of unquestionable interest but surprisingly little empirical evidence existed. Governments proceeded in the 1990s with an industrial organisation blueprint which separated Generation from Networks, and combined Retail with Distribution Networks. A second wave of industrial organisation was orchestrated by capital markets in the 2000s, splitting Retail from Distribution, and merging Retail with Generation. Many policymakers and regulators view the practice of vertical integration in a neoclassical sense; presenting risks of withholding capacity, increasing prices, raising barriers to entry, non-integrated rival foreclosure and damaging consumer welfare. But the weight of theoretical and empirical evidence points to the contrary, with transaction costs featuring prominently. In this article, a Generator and Retailer are simulated over 15 years of trade in Australia's National Electricity Market as stand-alone businesses, and then as a merged entity. A comparison of the Sum-Of-The-Parts with the Vertical Firm reveals non-trivial transaction costs and multi-stage economies of integration – the Vertical Firm reduces costs by 17% and volatility of earnings by 83%, which produces a 26% improvement in credit quality and lifts statutory profits by 34% holding prices and volumes constant.

Keywords: vertical integration, electricity markets, energy-only markets, transaction costs, credit ratings.

JEL Codes: D23, D24, D25, G34, L94.

1. Introduction

For most of the 20th Century the vertically integrated power industry was one of the leading sectors of the economy vis-à-vis productivity, scale economies and technology development (Joskow, 1987). By the 1980s sector performance deteriorated across countries such as the US, Great Britain and Australia (Joskow, 1987; Kellow, 1996; Newbery and Pollitt, 1997). Along with material capital misallocation, overcapacity and rising prices (Pierce, 1984; Hoecker, 1987) utility service boundaries were frequently economically meaningless (Fairman and Scott,1977).

Disaggregating vertical monopoly utilities[1] and creating competition within Generation and Retail segments can be traced as far back as Weiss (1973). As Landon (1983) explained, the basis of restructuring was i). economic regulation had failed (Stigler and Friedland, 1962; Stigler, 1971; Posner, 1974; Moore, 1975; Peltzman, 1976), ii). in Generation, scale economies were increasingly extracted at the plant level (Christensen and Greene, 1976; Huettner and Landon, 1978), iii). system coordination could be managed through contracts, iv). networks could be regulated

♣ Professor of Economics, Griffith Business School, Griffith University.
♠ Research Associate, Energy Policy Research Group, University of Cambridge.
[11] For an excellent discussion of the diversity of industrial organisation within the electricity industry prior to the reforms, see Schmalensee (2019).

as common carriers (Smith, 1996), and, v). a presumption that economies of scope and integration *were most likely minimal*. It was therefore thought electricity would be most efficiently supplied via specialised firms competing in their respective stages of production.

Limits to scale economies in power generation had been empirically documented as early as Christensen & Green (1976) and Huettner & Landon (1978) – key insights being the average total cost curve for power generation was very flat for a broad range of output. Moreover, technology changes (i.e. Combined Cycle Gas Turbine) meant scale-efficient entry was contracting after more than 60 years of unit size expansion (Joskow, 1987; Hunt and Shuttleworth, 1996; Meyer, 2012a). Consequently, policies promoting restructuring and competition could not be faulted on the grounds of scale economies. But presumptions that economies of integration *'were most likely minimal'* are surprising in hindsight. The presence of multi-stage economies of integration is an empirical question and remarkably little (if any) evidence existed prior to Kaserman and Mayo's (1991) pioneering work in the field.

Nonetheless, restructuring plans proceeded. Efficiency gains from competition focused on the Generation segment (Weiss, 1973; Fairman and Scott, 1977; Landon, 1983). This was justified given overcapacity and deteriorating economic performance (Pierce, 1984; Hoecker, 1987; Joskow, 1987; Newbery and Pollitt, 1997; Booth, 2000; Simshauser, 2005). The first practical electricity market experiment based on Weiss's (1973) constructs commenced in Chile from 1978 (Pollitt, 2004)[2]. Ground breaking work by Schweppe *et al.* (1988) on organised spot markets for electricity would lead to widespread adoption of industry restructuring and competitive markets. A wave of microeconomic reform swept through western economies during the 1990s, the centrepiece being vertical and horizontal disaggregation and creation of competitive wholesale and contestable retail markets, based on the landmark England & Wales pool (Newbery, 2005, 2006). Any notion that the industry was a natural vertical monopoly was dispelled.

In markets characterised by generation overcapacity, initial gains from competition were predictable, and non-trivial. By almost any measure Australia's National Electricity Market (NEM) could only be described as a miracle of microeconomic reform (Simshauser, 2014). The Australian policy program was typical, commencing with extensive vertical industrial re-organisation of state-owned vertical monopoly utilities by four State Governments, viz. Queensland (QLD), New South Wales, Victoria and South Australia.[3] Horizontal restructuring followed to create competition amongst Generation and Retail Supply. When the industrial organisation dust settled and System Operations and market mechanisms synchronised across the 4 regions, 15 rival portfolio Generators[4], four regional Transmission Networks and 14 Distribution/Retail Supply[5] entities emerged.[6] The industrial organisation *blueprint* segregated competitive segments from natural monopoly segments (Transmission, Distribution) and crucially, Generation was partitioned from Retail Supply.

In the NEM blueprint, the first wave of industrial organisation was driven by government and competition policy across vertical and horizontal dimensions. A second wave would be driven by capital markets across three dimensions (vertical, horizontal, geographic) in pursuit of optimal asset allocation, efficiency gains and profit maximisation.

---

[2] As Pollitt (2004) notes, vertical and horizontal restructuring was completed by 1981 and enabling legislation enacted in 1982.
[3] Throughout the 1990s, the four governments agreed to a common set of market rules and proceeded to vertically restructure their state-own vertical monopoly utilities into separate generation, transmission, and distribution/retail entities.
[4] This included 4 portfolio generators in QLD, 4 in NSW (including Snowy Hydro), 5 in VIC, 3 in SA.
[5] This included 2 in QLD, 6 in NSW, 1 in the ACT, 5 in VIC and 1 in SA.
[6] The NEM's 5th Region, Tasmania is somewhat complicated by the fact that it only joined the NEM in 2006, and for a range of reasons including politics and scale, remained a largely monopoly/monopsony regional market.

The first step involved vertical divestment of Retail from Distribution. Retail Supply ('Retailers') were initially stapled to a Distribution Network monopoly, a model common to Great Britain and Australia being *'the best that could be done at the time'* given complex business interfaces (Helm, 2014).[7] While customer interface costs (billing, call centres) are sub-additive, merchant Retailers are fundamentally different to regulated Distribution Networks and consequently, every Distribution Network in the NEM (and Great Britain) divested their Retail business. These vertical structural separations were 'value-driven' investor events – capital markets consistently undervalued Distributor-Retailer businesses.[8] Sum-Of-The-Parts valuations revealed divestment would yield higher total returns.

The corollary to this reorganisation was Retailers losing the 'credit-wrap' provided by their capital-intensive (investment-grade) Distribution Network parent company, and as Nillesen and Pollitt (2011, 2019) explain, the start of the loss of competitive intensity. The second step of industrial reorganisation that followed involved horizontal consolidation across geographies. The NEM's 14 incumbent Retailers lacked scale and progressively consolidated to remain competitive. Mergers & Acquisitions (M&As) occurred amongst privatised and government-owned Retailers.[9] Curiously, State and Commonwealth Governments and competition regulators waived all horizontal M&A events through – evidently prioritising *proceeds* and *privatisation* over *concentration* and *competition*.

The third step of industrial reorganisation was vertical integration by Retailers.[10] Looking back, an *'electricity market arms race'* played-out over 1995-2015. The NEM's 'Big 3' Retailers or *Gentailers*[11] emerged as winners from a string of horizontal, vertical and geographic privatisation and M&A events over a 20-year period.

Vertical re-integration has been deeply unpopular amongst some regulators and policymakers in Australia and Great Britain[12]. It has been a continual regulatory target and more recently in Australia, the subject of policy intrusion[13]. Opposition to firm boundary changes relates to concerns of vertical market power, withholding capacity, adverse impacts on forward market liquidity and foreclosure of rival (non-integrated) Retailers. By this logic, vertical integration is presumed to be highly anti-competitive. Yet the weight of theoretical and empirical evidence on vertical integration overwhelmingly concludes the opposite as Lafontaine & Slade (2007) and others[14] note. To the extent that market power events have occurred in the NEM, their source was horizontal power, not vertical power – something which seems to

---

[7] It also ensured Retailers had substantial asset backing.

[8] Networks have stable regulated returns, whereas Retailers exhibited increasingly volatile results - a natural outworking of retail contestability and the extreme volatility of wholesale prices in an energy-only market setting. Although in New Zealand, forced divestiture seemed to produce very little benefit and a loss on competition (Nillesen and Pollitt, 2011, 2019).

[9] Indeed, the States of QLD and NSW consolidated their own Retail Supply businesses from nine down to just four prior to, or during, privatisation processes in 2007 and 2011 respectively. There were originally three franchise retailers in Queensland and six in New South Wales. In Queensland, Origin Energy and AGL Energy purchased the retail businesses. In New South Wales, Origin Energy and Energy Australia purchased the retail businesses.

[10] Forward integration also became the dominant strategy amongst incumbent generators – many of which have formed large vertical businesses.

[11]Australia's 'Big 3' are AGL Energy, Origin Energy, EnergyAustralia. Two other large integrated rivals are Alinta Energy and Snowy Hydro (and retail business Red Energy). (Godofredo, de Bragança and Daglish, 2017) note the term *Gentailer* was commonly used in Great Britain, Australia & New Zealand, and first appears in the literature in (Meade, 2005).

[12] See for example ACCC's 2018 Restoring electricity affordability and Australia's competitive advantage Report, AER's 2011 State of the Energy Market Report, and in the case of Great Britain, see Ofgem's 2014 State of the Market Assessment Report.

[13] See the Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Bill 2019), known as the 'Big Stick Bill'.

[14] See for example (Cooper *et al.*, 2005; Mansur, 2007; Bushnell, Mansur and Saravia, 2008; Joskow, 2010; Simshauser, Tian and Whish-Wilson, 2015; Guo *et al.*, 2020).

have bedevilled Australia's competition regulators and policymakers (Simshauser, 2019a).

Vertical firms have been the NEM's historically dominant providers of new dispatchable plant capacity (i.e. >75% of gas-fired generation plant). Yet from 2016-2019 vertical utilities appeared to have stalled new capacity investments despite tightening reserve plant margins. The NEM experienced an acute business cycle from 2012-2019 and new patterns of relative pricing emerged reflecting rising Variable Renewable Energy. Is it possible that market conditions have muted multi-stage economies that previously existed?

The purpose of this article is to analyse vertical integration amongst merchant utilities in the NEM – why it occurs, why it matters to the flow of investment and how material multi-stage economies of integration are in Australia's energy-only market setting. In doing so, this research simulates two businesses from 2004/05-2018/19; viz. i). a pure-play Retailer and ii). a merchant Generator of unequal size. The two firms are then *merged* and compared to the Sum-Of-The-Parts. Use of half-hourly spot prices, forward contract prices, and yearly retail tariffs over a 15-year window produces rich insights into industrial organisation in energy-only markets.

Results confirm material transaction costs exist when Generation and Retail are partitioned – cumulative costs rise by ~17%, reported earnings fall by ~35% and credit quality deteriorates by 26% (holding consumer prices and volumes constant). The credit quality of stand-alone businesses are 'junk' whereas the vertical firm exhibits investment-grade metrics. Market frictions including bounded rationality, instability of wholesale prices, incompleteness of forward markets, asymmetric information, regulatory discontinuities and investment under uncertainty are the sources of multi-stage economies of integration. Stalling of new investment in peaking capacity must therefore be explained by other reasons, the most prominent candidate being random and capricious political interventions aimed at large vertical firms.

This article is structured as follows. Section 2 provides an expansive literature review on vertical arrangements. Section 3 introduces data and models. Section 4 presents results. Conclusions follow.

2. Review of Literature

There is no unifying theory of vertical integration. The complexity of forces favouring or opposing various forms of industrial organisation make a general theory intractable (Green, 1986; Joskow, 2010). Two broad schools of thought exist[15] on the motives for vertical integration, i). neoclassical theories which emerged in the 1950s (see Bain, 1956) and ii). transaction cost theories, sparked by Williamson (1971).

2.1 Neoclassical theories of vertical integration

The neoclassical view considers vertical integration as a means by which firms acquire market power, withhold intermediate supplies, raise barriers to entry and foreclose non-integrated rivals (Bain, 1956). The neoclassical view is underpinned by assumptions of perfectly competitive markets, costless spot market transactions and plant-level scale economies. Transaction costs are ignored, and multi-plant scale and multi-stage scope economies are assumed away (Williamson, 1971). Consequently, vertical arrangements are considered an anomaly. This view was translated into policy; the first US Department of Justice 'merger guidelines' (1968) were relatively hostile towards vertical activity due to perceived risks of vertical

[15] While Transaction Cost Economics dominates the literature, two variations are worth noting i). property rights-based theories vis-à-vis asset specificity, contractual incompleteness and opportunistic behaviour as key motivations to maximise the value of ex-post vertical investment decisions (Grossman and Hart, 1986; Hart and Moore, 1990), and ii). principal-agent based theories of vertical integration, which can be classed as theories of moral hazard (Lafontaine and Slade, 2007).

foreclosure of un-integrated rivals (Reiffen and Vita, 1995; Lafontaine and Slade, 2007; Michaels, 2007).

Neoclassical theory dissipated during the 1970s following Peltzman (1969) and others who highlighted that if a post-integrated firm has market power in one segment, that same level of market power existed prior to vertical integration. However, theories of economic harm re-emerged within a game-theoretic framework from the 1980s. In Salinger (1988), vertical practices were considered in a generalised Cournot oligopoly environment in both the primary and downstream market. Vertical integration was shown to increase input costs of unintegrated rivals, thereby reducing their output and adversely affecting welfare. However, amongst vertical firms double mark-ups[16] were eliminated (an efficiency benefit of integration) and output expanded – the net effect on welfare therefore being ambiguous.

Game-theoretic models typically showed vertical firms withholding capacity, raising input costs of non-integrated rivals, with model outcomes being foreclosure (see for example Salop and Scheffman 1983, 1987; Salinger, 1988; Ordover, Saoloner and Salop, 1990; Martin, Normann and Snyder, 2001). But models underpinning neoclassical theories of harm are fragile as Reiffen and Vita (1995) and Cooper et al. (2005, p641) explain:

> *…anticompetitive equilibria emerge only under specific – and difficult to verify – assumptions about (among other things) costs, demand, the nature of input contracts, conditions of entry, the slope of reaction functions and the information available to firms. Seemingly minor perturbations to these assumptions can reverse the predicted welfare effects of the practice in question…*

A vast literature on vertical integration spanning well over 500 articles exists, with surprisingly little empirical evidence supporting the neoclassical view (Lafontaine and Slade, 2007; Joskow, 2010).

2.2 Transaction cost theories of vertical integration

Economic theory and empirical evidence on vertical integration is dominated by transaction cost motives (Joskow, 2010). The existence and importance of transaction costs is generally attributed to Coase (1937) who examined why firms exist at all in an exchange economy. But it was Williamson (1971, 1973, 1975) who predicted changes to firm boundaries when confronted with transaction costs, market fictions and hazards associated with i). asset specificity and technical dependencies, ii). bounded rationality, iii). contractual incompleteness, iv). security of supply, v). regulatory risk and vi). asymmetric information and uncertainty.

Transaction cost theories explain that these variables create hazards for ex-ante investment commitment, and ex-post performance. Faced with any or all of these conditions, vertical mergers achieve more adaptive, sequential decision-making procedures as market conditions change *cf.* anonymous spot and forward market transactions (Williamson, 1973). Put simply, the internal laws of the firm are more pliable than contract law. Vertical arrangements better harmonise conflicting interests and result in less costly ‘sequential adaptation’ to uncertain business conditions over time (Williamson, 1971).

An expansive economics literature explores operating efficiencies as a crucial driver of vertical M&A events (Simon, 1955; Williamson, 1979; Landon, 1983; Grossman

[16] The issue of eliminating double mark-ups is best explained by reference to a two-stage monopoly industry where both upstream and downstream monopolists independently add profit margins (i.e. double marginalisation). Because neither firm knows the true marginal cost of supply, prices are set above the profit maximising level. Integration removes imperfect information and results in the integrated firm setting a lower price, expanding output, and increasing firm profits and consumer welfare.

and Hart, 1986; Stuckey and White, 1993; Holmström and Roberts, 1998). Literature from financial economics concludes decisions to vary firm scope are optimised when targets have similar earnings volatility, asset complementarity, and low earnings correlation coefficients (Flannery, Houston and Venkataraman, 1993; Chemmanur and John, 1996; Homberg, Rost and Osterloh, 2009; Simshauser, Tian and Whish-Wilson, 2015; Teti and Tului, 2020).[17]

2.3 Electricity markets and transaction costs

Economic theory and power system modelling has long demonstrated organised spot markets clear demand reliably and provide investment signals for new plant (Schweppe et al. 1988), and, that scale economies in power generation do not require large regional monopoly portfolios (Christensen and Greene, 1976).[18] This suggests electricity markets are best served by specialised firms with gains from competition counterbalancing losses of multi-stage economies of integration.

Electricity market theory and modelling is based on equilibrium analysis and underpinned by an extensive list of explicit and implicit assumptions including unlimited market price caps, perfect capital markets, complete forward markets, limited political/regulatory interference and capital structures able to withstand elongated energy market business cycles (Simshauser, 2010; Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz *et al.*, 2019). But as Malmgren (1961) noted, deviations from idealised models of perfect competition are the usual state of affairs. Central to those deviations are the capital-intensive nature of generating equipment and the central role that debt capital plays vis-à-vis investment commitment. Multi-stage economies of integration had historically provided a source of coordination benefit, including access to low cost finance (Newbery, 2005).

In the electricity market blueprint, stand-alone merchant generators selling output into organised spot and forward markets would be underpinned by long-dated non-recourse project finance – a form of finance first originated in 1981 and well-suited to capital-intensive investments (Simshauser and Nelson, 2012). However, electricity markets turned out to be much tougher operating environments than originally thought. Persistent generator pricing at marginal cost produced inadequate revenues given substantial sunk costs – a problem understood as far back as Hotelling (1938), Boiteux (1949) and Turvey (1964). In restructured energy markets, Cramton and Stoft (2005, 2006) labelled this 'the missing money' (Peluchon, 2003; Simshauser, 2008; Bajo-Buenestado, 2017; Keppler, 2017; Milstein and Tishler, 2019).

While the theory is based on equilibrium, electricity markets are typically *off equilibrium* for extended periods (de Vries and Heijnen, 2008; Hirth, Ueckerdt and Edenhofer, 2016). Because merchant generators face rigid debt repayment schedules, theories of organised spot markets suffer from an inadequate treatment of how non-trivial sunk capital costs are financed (Joskow, 2006; Finon, 2008; Simshauser, 2010; Caplan, 2012).

Von der Fehr and Harbord (1995) first observed that indivisibility of capacity, construction lead-times, lumpy entry, investment tenor and policy uncertainty make merchant generation investments unusually risky. Early contributions on market frictions which focused on the special complexity of peaking plant investments include Doorman (2000), Besser et al. (2002), Stoft (2002), de Vries (2003), Oren

[17] In Modigliani and Miller (1958) and their classic framework without taxes, bankruptcy costs, information asymmetries and agency costs, a formal mathematic proof demonstrated that capital structure was irrelevant and that no such synergies could exist. However, when the simplifying assumptions were relaxed, capital structure was found to be important, and this implies changes in firm scope can create financing efficiencies as well as operating efficiencies (Leland, 2007; Simshauser, Tian and Whish-Wilson, 2015).
[18] See also Huettner and Landon (1978), Joskow (1987), Hunt and Shuttleworth (1996) and Meyer (2012a).

(2003) and Peluchon (2003).[19] Entire editions of academic journals have been dedicated to the topic.[20] Indeed, once the implicit and explicit assumptions underpinning electricity market theory are relaxed and transaction costs introduced, it can be shown that energy-only markets with an administratively determined Value of Lost Load (VoLL) can only reach a stable equilibrium when the power system is operating near the edge of collapse (Bidwell & Henney, 2004).

In theory, a high VoLL provides the means by which to bridge equilibrium conditions but rival electricity market participants are unable to optimise the number of VoLL events (Cramton et al. 2013). Further, actions by regulators and System Operators frequently suppress legitimate price signals (Joskow, 2008; Hogan, 2013; Spees, Newell and Pfeifenberger, 2013; Leautier, 2016)[21]. Australia's NEM is also suffering from various forms of random political interventions (Simshauser, 2019b; Wood, Dundas and Percival, 2019). Consequently, there is considerable evidence to suggest timely entry on a merchant basis is no longer possible (Finon 2008 and others[22]). To be clear, merchant plant will eventually enter if prices are high enough. But the political economy of such prices, and the market conditions which generate them, makes this highly problematic.

This is more than a theoretical discussion. In the early phases of the global restructuring experiment, a vast fleet of merchant plant was project financed on the basis of spot prices and short-term forward contracts. But recurring damage to merchant generator profit & loss statements arising from structural oversupply and episodes of *missing money* led project banks to tighten credit parameters (Simshauser, 2010). By 2004 a surprisingly large proportion of merchant plants in the US, Great Britain and Australia experienced financial distress, capital restructuring or outright bankruptcy (Joskow, 2006; Michaels, 2007; Finon, 2008; Simshauser, 2010).[23] This re-set preconditions for project finance – the main implication being new entrant merchant plant could no longer obtain project finance (as Section 4.1 later demonstrates).

Central to this is *incomplete markets* – the inability of electricity markets to deliver the optimal mix of derivative instruments required to facilitate efficient plant entry, specifically, long-dated contracts sought by risk averse project banks as Newbery (2016) and others[24] note. Australia's NEM is noted for favourable forward market liquidity[25] (Fig.1). But activity spans 3 years, well short of optimal financing structures. Forward markets have failed to calibrate beyond this because competitive Retailers cannot afford to hold hedge portfolios dominated by inflexible long-dated contracts when large components of their customer book switch supplier every 2-3 years (Newbery 2006, Anderson et al. 2007 amongst others[26]).

Concerns over timely plant investment are compounded by the fact that large segments of real-time aggregate demand are price-inelastic and unable to react to

---

[19] See also Bushnell, 2004; Wen, Wu and Ni, 2004; Neuhoff and De Vries, 2004; Hogan, 2005, 2013; Roques, Newbery and Nuttall, 2005; Cramton and Stoft, 2006; Simshauser, 2008; Finon, 2008; Finon and Pignon, 2008; Joskow, 2008; Spees, Newell and Pfeifenberger, 2013; Cramton, Ockenfels and Stoft, 2013.
[20] See *Utilities Policy* Volume 16 (2008) and *Economics of Energy & Environmental Policy* Volume 2 (2013).
[21] See also Besser, Farr and Tierney, 2002; de Vries, 2003; Oren, 2003; Wen, Wu and Ni, 2004; Batlle and Pérez-Arriaga, 2008; Finon and Pignon, 2008.
[22] See also Bidwell and Henney, 2004; Cramton and Stoft, 2006; de Vries and Heijnen, 2008; Roques, 2008; Howell, Meade and O'Connor, 2010; Simshauser, 2010; Caplan, 2012; Nelson and Simshauser, 2013; Simshauser, Tian and Whish-Wilson, 2015; Hirth, Ueckerdt and Edenhofer, 2016.
[23] By 2005, more than 110,000 MW of merchant plant in the US, much of the Australian merchant fleet and various high profile plant in the UK (e.g. Drax) experienced financial distress or bankruptcy (Joskow, 2006; Finon, 2008; Simshauser, 2010).
[24] See Joskow, 2006; Chao, Oren and Wilson, 2008; Meade and O'Connor, 2009; Howell, Meade and O'Connor, 2010; Caplan, 2012; Meyer, 2012b; Nelson and Simshauser, 2013; Newbery, 2017, 2016; Grubb and Newbery, 2018; Bublitz *et al.*, 2019.
[25] See Chester, 2006; Anderson, Hu and Winchester, 2007; Howell, Meade and O'Connor, 2010; Simshauser, Tian and Whish-Wilson, 2015; Nelson *et al.*, 2019; Simshauser, 2020.
[26] See also Green, 2006; Finon, 2008; Howell, Meade and O'Connor, 2010; Simshauser, 2010.

scarcity conditions, and in the short run, supply is inelastic because storage remains costly (Batlle and Pérez-Arriaga, 2008; Cramton and Stoft, 2008; Finon and Pignon, 2008; Roques, 2008; Bublitz *et al.*, 2019).[27]

To summarise, the energy economics literature reveals electricity markets are littered with market frictions of the type that Williamson (1971, 1973, 1975, 1979) had articulated decades earlier, including high asset specificity, bounded rationality, asymmetric information between Generation and Retail, long asset lives, and unusually high financial hazards with ex-ante capital-intensive investment commitments (Roques, Newbery and Nuttall, 2005; Simshauser, 2010; Simshauser, Tian and Whish-Wilson, 2015). And as Williamson predicted, industrial organisation is the means by which firms navigate market frictions, market complexity and market imperfections. Vertical integration has emerged as the dominant industrial form *because* the market for forward contracts is incomplete and *because* attempts to write long-dated contracts suffer from bounded rationality, asymmetric information and acute uncertainty given the timeframes involved vis-à-vis financing. Ultimately, merchant plant entry is facilitated by vertical integration, not in spite of it.

2.4 Economies of Integration: Electricity Utilities

As Michaels (2007), Arocena (2008) and Nillesen and Pollitt (2011) explain, when proposals for industry restructuring were emerging, multi-stage scope economies should have been of unquestionable interest but surprisingly little empirical evidence existed prior to the pioneering work by Kaserman and Mayo (1991). Their analysis did not question competition gains but focused on the ‘cost’ component of the cost-benefit calculus of restructuring. Results revealed multi-stage losses from disaggregation being (on average) ~12% across 74 utilities. A small but growing body of research ensued in two broad streams, i). cost subadditivity and coordination losses from disaggregation, and ii). motivations for and welfare implications of vertical re-aggregation vis-à-vis prices and competition. Some have pursued both lines of inquiry (Kwoka and Pollitt, 2010; Meyer, 2012a, 2012b).

To summarise the literature on cost subadditivity and coordination, virtually all studies confirm the existence of multi-stage economies (Gilsdorf, 1995; Hayashi, Goo and Chamberlain, 1997; Kwoka, 2002; Jara-Díaz, Ramos-Real and Martínez-Budría, 2004; Nemoto and Goto, 2004; Fraquelli, Piacenza and Vannoni, 2005; Arocena, 2008; Fetz and Filippini, 2010; Gugler, Liebensteiner and Schmitt, 2017).[28] Separating Generation from Networks typically results in coordination losses in the range of 2-10% whereas partitioning Generation from Retail produces multi-stage cost structure losses of 20-40% (Kwoka, 2002; Meyer, 2012b, 2012a; Gugler, Liebensteiner and Schmitt, 2017).[29] While not contemplating electricity, the reason for this large permanent loss can be traced back to Carlton (1979) – vertical arrangements are a means by which to transfer market risks and uncertainty from one part of the economy to another (i.e. spot and forward markets cannot be relied upon to achieve the socially desirable allocation of risk and production in all circumstances).

The second stream of literature focuses on whether mergers between Generation and Retail are anti-competitive or driven by transaction costs (Hogan and Meade,

[27] High levels of Variable Renewable Energy (VRE) amplifies and complicates matters, because historically such plant has been subsidised in certificate ‘side-markets’ and priority dispatched (Joskow, 2013; Newbery, 2015; Simshauser, 2018).
[28] Although (Gilsdorf, 1995) did not find cost complementarity, he did not preclude the presence of scope and integration economies (in fact several results in his study exhibited as much).
[29] Hayashi et al (1997) estimate between 14-17% gains amongst US utilities. Kwoka (2002 p.664) estimates gains from Generation & Retail integration of 27-42% (median, mean) for across 147 utilities. Nemoto & Goto (2004, p.80) find 0.13-2.97% in Japan, Jara-Diaz et al. (2004, p.1007) find 6.5% plus market costs in Spain. Fraquelli et al (2005, p.306) of 3% for the average sized Italian utility and gains of up to 40% for large operators, Arocena (2008) finds between 1.1-4.9% in Spain. Fetz & Filippini (2010) find vertical economies of 40%+ in Switzerland. Gugler et al. (2017 p.453) find 14-51% (median, mean) across 28 European Utilities.

2007; Mansur, 2007; Bushnell, Mansur and Saravia, 2008; Simshauser, 2010; Boroumand and Zachmann, 2012; Simshauser, Tian and Whish-Wilson, 2015; Godofredo, de Bragança and Daglish, 2017; Guo *et al.*, 2020). Putting energy markets to one side, a vast literature on vertical integration across multiple industries exists from Malmgren (1961) with marked acceleration following Williamson (1975). Cooper *et al.*(2005), Lafontaine and Slade (2007) and Joskow (2010) provide extensive surveys, covering hundreds of theoretical and empirical studies and to summarise, the weight of empirical evidence points to material gains in consumer welfare including in profit-maximising vertical decisions. Furthermore, the literature contains considerable evidence of adverse impacts to consumers when the practice is banned (Borenstein, Bushnell and Wolak, 2002; Nillesen and Pollitt, 2011).[30] Indeed, as Cooper *et al.* (2005) note, the striking feature of the literature is how little empirical evidence there is that demonstrates anti-competitive effects arise through vertical arrangements in competitive markets (setting to one side horizontal market power and bottleneck infrastructure). Empirical studies on petrol, beer, retail, cable television and merchant electricity provide strong quantitative evidence that vertical arrangements were welfare enhancing by reducing final prices, increasing output, or both (Barron and Umbeck, 1984; Shepard, 1993; Mullin and Mullin, 1997; Slade, 1998; Vita, 2000; Chipty, 2001; Bushnell, Mansur and Saravia, 2008).

Reiffen and Vita (1995) considered an environment in which the primary market was comprised of Cournot oligopolists while the downstream market comprised a differentiated Bertrand duopoly[31] – an analogous framework for energy markets. In wholesale markets, forward contract volumes are known to be extremely important (Allaz and Vila, 1993). With increasing forward sales commitments generators are less inclined to exercise market power in spot markets (Powell, 1993; Newbery, 1998; Green, 1999; Mansur, 2007; Bushnell, Mansur and Saravia, 2008; Gans and Wolak, 2011; Guo *et al.*, 2020). Retail markets are characterised by second- and third-degree price discrimination with product bundling and customer poaching. Armstrong (2006, 2008) provides an expansive survey of the literature on price discrimination under conditions of asymmetric markets and concludes where differential prices form a central component of final tariffs, competitive offers are lower when second-period commitments can be made.

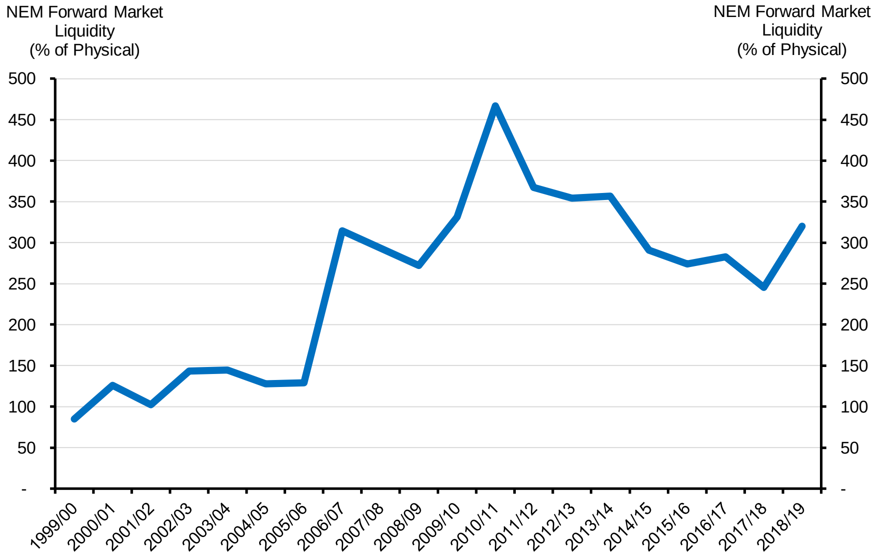
Consequently, vertical arrangements between Generators and Retailers create two forces; firm forward sales commitments (for Generation) and ability to make second-period commitments (for Retail); from this it follows that vertical activity can be expected to be pro-competitive. Empirical studies support this view. In electricity markets where vertical arrangements were temporarily banned or forward commitments suboptimal, wholesale prices exceeded efficient levels (Newbery, 1998; Green, 1999; Borenstein, Bushnell and Wolak, 2002; Kahn and Joskow, 2002; Mansur, 2007; Bushnell, Mansur and Saravia, 2008). Mansur 2007 and Bushnell et al (2007) find vertical arrangements had a clear moderating effect on wholesale prices in the PJM market. Analysing the New Zealand market, Hogan and Meade (2007) found vertical integration to be a more efficient business model through

[30] Lafontaine & Slade (2007, p.680) citing more than 200 sources, summarise the literature as follows: *As to what the data reveal in relation to public policy, we did not have a particular conclusion in mind when we began to collect the evidence, and we have tried to be fair in presenting the empirical regularities. We are therefore somewhat surprised at what the weight of the evidence is telling us. It says that, under most circumstances, profit maximizing vertical-integration decisions are efficient, not just from the firms' but also from the consumers' points of view. Although there are isolated studies that contradict this claim, the vast majority support it. Moreover, even in industries that are highly concentrated so that horizontal considerations assume substantial importance, the net effect of vertical integration appears to be positive in many instances. We therefore conclude that, faced with a vertical arrangement, the burden of evidence should be placed on competition authorities to demonstrate that that arrangement is harmful before the practice is attacked. Furthermore, we have found clear evidence that restrictions on vertical integration that are imposed, often by local authorities, on owners of retail networks are usually detrimental to consumers. Given the weight of the evidence, it behoves government agencies to reconsider the validity of such restrictions.*

[31] Reiffen and Vita (1995) found downward pressure applied to final prices from eliminating double mark-ups more than offset the effect of higher input prices to un-integrated rivals. They concluded vertical arrangements tend to increase consumer welfare.

avoided double marginalisation, with market power reduced significantly, enhanced wholesale market competition and lower retail prices as does Guo *et al.*, (2020) in the case of China.[32] In Australia's NEM, the combined market share of the Big 3 is ~63% of retail and ~50% of generation but as Figure 1 illustrates, there is no evidence of 'withholding' or declining forward liquidity. Neither is there evidence of rival foreclosure; in 2018/19 the NEM had 35 active Retailers – up from 16 in 2006/07.[33]

Figure 1: NEM forward liquidity 1999/00-2018/19



Source: Simshauser (2020)

To summarise, energy markets are littered with non-trivial transaction costs. When firms are confronted with transaction costs and hazards associated with asset specificity, bounded rationality, incomplete markets, asymmetric information and uncertainty – vertical integration is predictable (Williamson, 1971). The energy economics literature identifies large permanent losses in multi-stage scope economies (c.20-40%) when Generation and Retail are partitioned. This leads to a quantitative analysis of vertical integration amongst merchant utilities.

3. Businesses, data and model framework

In this research, a 3x180MW merchant Open Cycle Gas Turbine (OCGT) and a Retailer with 5300GWh of load (Table 1) are simulated over a 15 year period using historic data from the NEM's QLD region. The 540MW peaking Generator forms a small component of QLD's 14,500MW supply-side, and the Retailer has a ~20% market share of the 'mass market' (i.e. residential and SME segments) and in aggregate represents less than 10% of QLD's final energy demand of 55,000GWh and peak demand of 10,000MW. Thus, neither business is dominant. When the entities are subjected to an M&A event, the integrated firm will be 'short' baseload and marginally 'long' peaking capacity. Details of the businesses, data and models are as follows.

[32] Gans and Wolak (2011) present one of the few dissenting views on the pro-competitive effects of vertical arrangements in energy market however their research focused on a passive synthetic vertical arrangement without control.

[33] In 2018/19, this includes the Big 3 incumbents, 29 entrants and 2 government franchises (Tasmania and regional QLD). In 2006/07 there were 8 incumbents, 5 entrants and 2 government franchises. See the Australian Energy Regulator's annual *State of the Market* reports at www.aer.gov.au

Table 1: OCGT and Retailer Assumptions (2004/05)

Open Cycle Gas Turbine (OCGT)			Pure Play Retailer		
Unit Size	(MW)	180	Customer Data		
Number of Units		3	Residential Customers		288,242
Capacity	(MW)	540	SME Customers		41,177
Caital Cost	($/kW)	850	Residential Load*	(GWh)	2,123
Acquisition Prie	($m)	459.0	SME Load*	(GWh)	910
Operations			C&I Load^	(GWh)	1,452
Annual Availability	(%)	94.0	Total Retail Load	(GWh)	4,485
Thermal Efficiency	(%)	31.9	Mass Mkt Max Demand	(MW)	647
Heat Rate	(GJ/MWh)	11.3	C&I Maximum Demand	(MW)	285
Unit Fuel Cost*	($/GJ)	2.91	Portfolio Max Demand	(MW)	778
Variable O&M	($/MWh)	3.00	Acquisition Values		
Fixed O&M	($/MW/a)	10,000	Mass Market Customers	(per cust)	$800
Major Inspections	($m)	15.0	C&I Customers	($/MWh)	1.50
Useful Life	(Yrs)	40	Acquisition Price	($m)	265.7
Taxation Life	(Yrs)	30	65% of which is Goodwill	($m)	172.7
* 10 Yr Gas Supply Agreement, then spot gas prices.			* Sales terms 90 days, 1% bad debts.		
			^ Sales terms 30 days, 1% bad debts.		

3.1 Data

In order to simulate the operations (i.e. plant dispatch, Retail portfolio hedging) and the financial stability (i.e. Profit & Loss, Balance Sheet, Cash Flow Statements, Asset Registers, Taxation Schedules, Debt Schedules) of the two businesses, data used is necessarily extensive and includes i). 30-minute resolution spot prices and customer load from AEMO, ii). traded derivatives prices (base & peak swaps, $300 caps) from the ASX, and daily natural gas prices from AEMO, iii). monthly average data from the capital markets (interest rate swaps, spreads and bond yields) from the RBA, and iv). annual retail customer switching rates, two-part tariffs for each segment, and prevailing tariff discounts (vis-à-vis price discrimination for strong and weak segment products) from AEMO and the QCA.[34] Recall the key motivation for this research is whether vertical integration remains the 'dominant form'. Various trends in the data are worth highlighting.

3.1.1. Spot electricity prices

Table 2 and Figure 2 present spot price data including Average Spot Prices, historic settlement value of $300 Caps (8th column) and the number of price spikes >$300 (scarcity events/market power events) in each year.

Table 2: QLD Spot Prices (2004/05 – 2018/19)

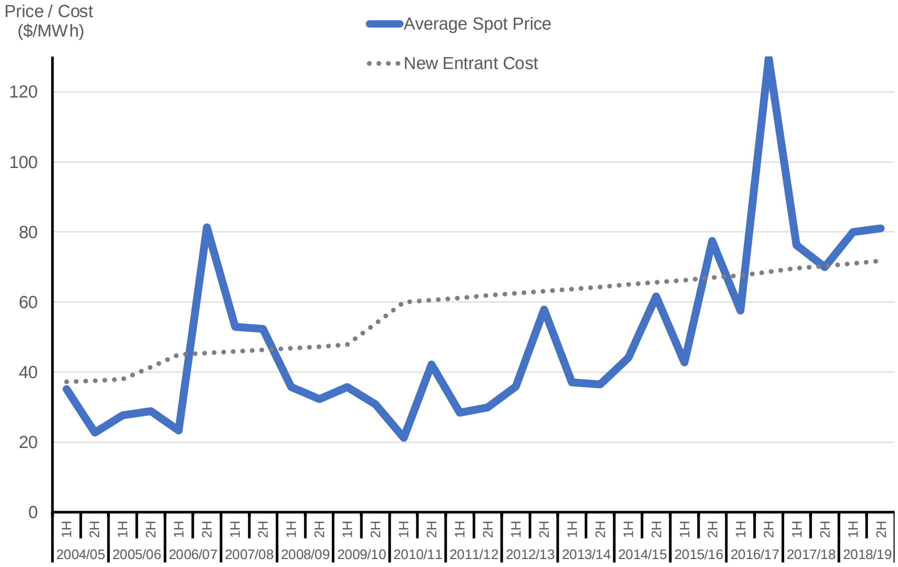
Fin Year	Observations	Average Spot Price	Standard Deviation	Skewness	Kurtosis	Coefficient of Variation	Fair Value of $300 Caps	Number of Price Spikes > $300
	(t)	($/MWh)	($/MWh)	($/MWh)	($/MWh)		($/MWh)	
2004/05	17,520	28.92	109	38	1,797	3.78	3.34	42
2005/06	17,520	28.20	181	35	1,351	6.40	5.59	41
2006/07	17,520	52.34	236	26	753	4.51	9.75	132
2007/08	17,568	52.61	281	25	711	5.34	12.80	77
2008/09	17,520	34.03	106	43	2,487	3.12	2.93	35
2009/10	17,520	33.26	199	31	1,116	5.99	7.42	47
2010/11	17,520	31.66	178	37	1,528	5.63	5.26	37
2011/12	17,568	29.15	46	54	3,436	1.59	0.70	22
2012/13	17,520	67.54	126	22	657	1.86	6.13	168
2013/14	17,520	58.46	106	21	489	1.81	4.56	59
2014/15	17,520	52.79	353	26	803	6.69	18.25	106
2015/16	17,568	60.09	147	17	343	2.44	7.45	86
2016/17	17,520	93.58	331	26	848	3.53	17.75	176
2017/18	17,520	73.05	42	31	1,484	0.57	0.52	9
2018/19	17,520	80.55	39	16	866	0.48	0.20	15
Total	262,944	51.53	192	36	1,711	3.74	6.84	1,054
2020$		59.89					8.15	

Source: AEMO.

For context, Figure 2 compares six-monthly average spot prices with estimated New Entrant Costs.

[34] AEMO is the Australian Energy Market Operator, ASX is the futures exchange, RBA is the Reserve Bank of Australia and QCA is the Queensland Competition Authority.

Figure 2: QLD Spot Prices[35] vs New Entrant Cost (2004/05 - 2018/19)



Source: AEMO, (Simshauser and Gilmore, 2019)

3.1.2. Gas Prices

Generation plant commences with a 10-year fixed price Gas Supply Agreement ($2.90/GJ) as was typical in the mid-2000s. During 2014-2016 a fleet of LNG export facilities were commissioned in QLD which linked NEM gas prices to seaborne market prices. Consequently, the OCGT plant operates from the day-ahead gas market thereafter. Gas prices are illustrated in Table 3 and Figure 3.

Table 3: QLD gas prices (2004/05-2018/19)

	10 Year	Brisbane Short Term Trading Market					Spark Spread	
	Contract Price	Spot Price	Std. Dev.	Coeff. Var.	Max Price	Min Price	CCGT*	OCGT^
	($/GJ)	($/GJ)	($/GJ)		($/GJ)	($/GJ)	($/MWh)	($/MWh)
2004/05	2.93						8.38	1.21
2005/06	3.01						7.10	7.94
2006/07	3.13						30.44	39.81
2007/08	3.24						29.96	32.11
2008/09	3.38						10.35	7.40
2009/10	3.46						9.02	9.92
2010/11	3.57						6.64	3.21
2011/12	3.67	3.59	0.71	0.20	5.65	2.60	4.00	-6.55
2012/13	3.73	5.92	1.53	0.26	12.90	3.62	26.12	8.17
2013/14	3.82	4.55	1.18	0.26	8.38	2.05	26.64	11.23
2014/15		2.28	2.15	0.95	29.90	0.00	36.86	42.07
2015/16		4.65	1.80	0.39	11.95	0.55	27.56	16.44
2016/17		8.19	2.48	0.30	16.50	3.41	36.22	19.00
2017/18		7.45	1.12	0.15	14.11	5.39	20.89	-6.06
2018/19		9.41	0.80	0.08	11.50	6.56	14.66	-18.85

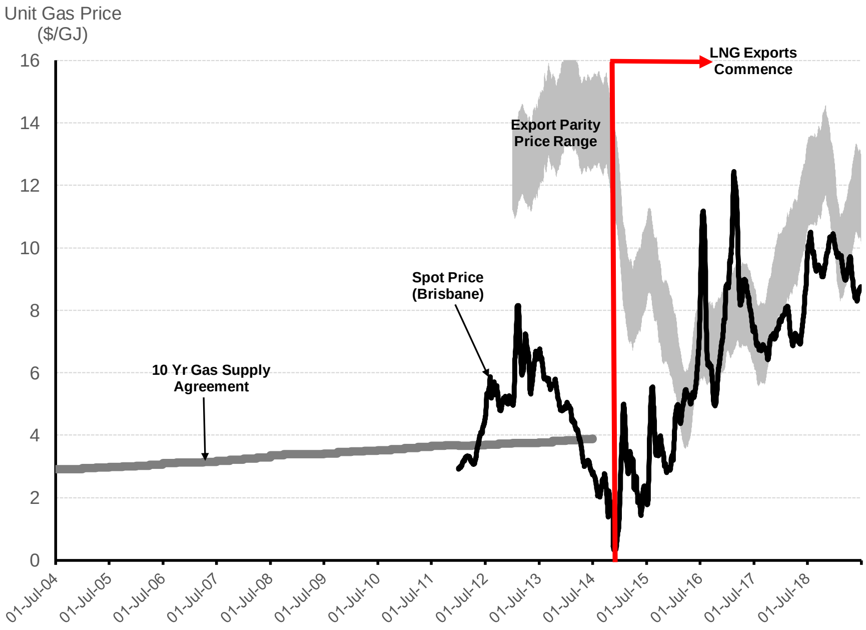
* CCGT Spark Spread: Average Annual Spot Price - (Gas Price x CCGT Heat Rate 7GJ/MWh). Gas spot prices used from 2011/12.

^ OCGT Spark Spread: Average Annual Peak Spot Price - (Gas Price x CCGT Heat Rate 11.3 GJ/MWh). Gas spot prices used from 2011/12.

Source: AEMO

[35] The spot price series excludes the effect of the Carbon Tax ($23/t) in 2012/13 and 2013/14.

Figure 3: QLD gas prices (2004/05 – 2018/19)



Source: GMAT

3.1.3. Forward Prices

Forward prices for the three most commonly traded derivative instruments (base swaps, peak swaps, $300 caps) have been drawn from futures market data. An overview of the data is presented in Table 4. Box A of Table 4 shows base prices. Note spot prices have 262,944 observations (i.e. 30 minute data over 15 years) with an average annual price of $51.53/MWh in nominal terms. Swaps data includes 16,919 days of trades (i.e. each business day over the period 2002-2019, noting that swaps for 2005 delivery commence trade three years prior, in 2002) and exhibit an overall average price of $52.29 in nominal terms. The 'Portfolio' result has 15 observations (i.e. one for each year of this study) with an average price of $50.65/MWh and represents an 'accumulated portfolio' of derivative instruments.[36]

Table 4: Base, Peak and $300 Cap Prices (2005-2019)

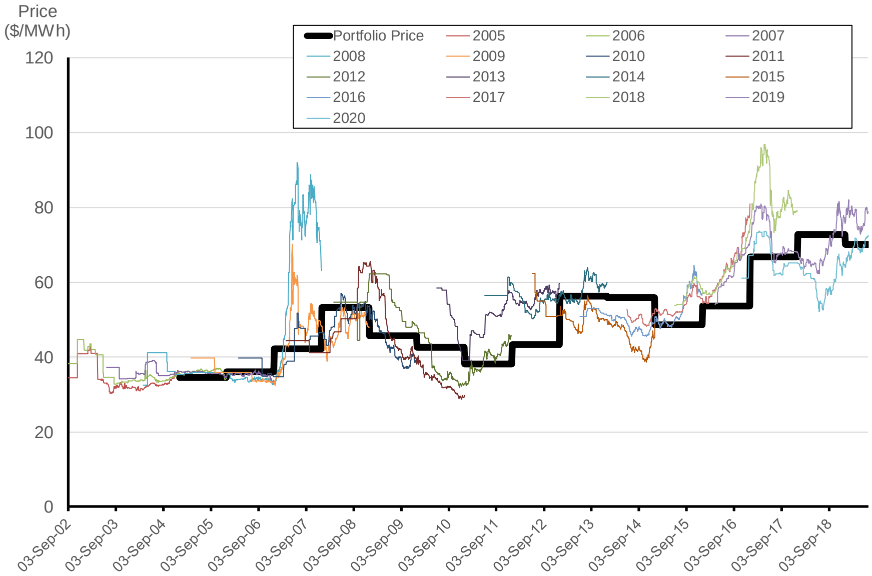
		Box A: Base Prices			Box B: Peak Prices			Box C: $300 Cap Prices		
		Spot	Swaps	Portfolio	Spot	Swaps	Portfolio	Spot >300	$300 Caps	Portfolio
Observations		262,944	16,919	15	143,820	16,919	15	262,944	13,123	15
Average	($/MWh)	51.53	52.29	50.39	62.60	69.38	68.63	6.84	8.62	9.56
Std Deviation	($/MWh)	20.78	14.88	11.85	21.48	18.03	12.24	5.69	4.04	2.25
Coeff. Variation		0.40	0.28	0.24	0.34	0.26	0.18	0.83	0.47	0.24
Min	($/MWh)	28.20	19.40	34.46	33.92	22.50	48.63	0.20	0.05	6.88
Max	($/MWh)	93.58	129.44	72.28	110.97	178.42	88.40	18.25	34.10	13.96

Source: AEMO, ASX.

Daily resolution, run-of-trade prices for Baseload Swaps and $300 Caps (2005-2020 vintages) and the constructed Swap and Cap portfolio prices (solid black line series) are presented in Figures 4 and 5 respectively.

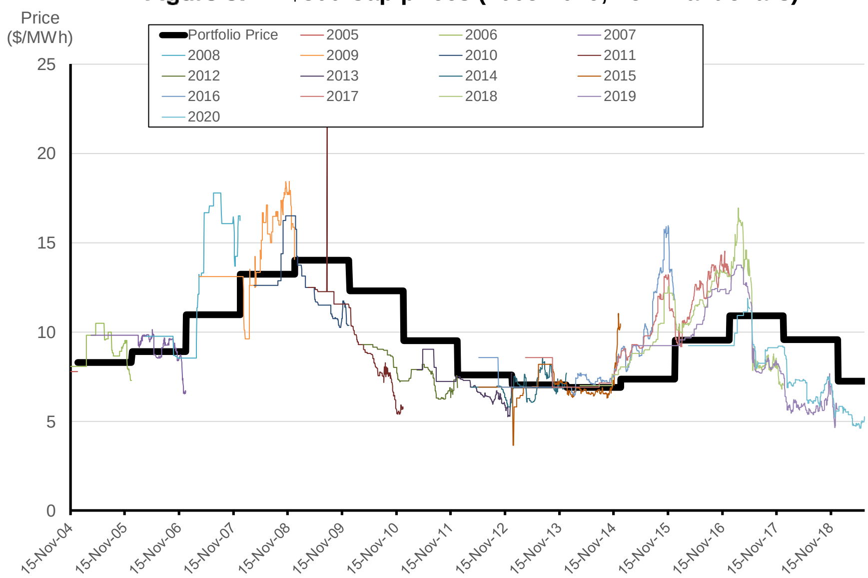
[36] Specifically, the accumulated portfolio involves progressively layering in base swaps into a portfolio over the three-year period leading up to real-time at the pre-set /vanilla hedge portfolio ratio of 20%, 35% and 45% in years n-3, n-2 and n-1 respectively. The same process applies to peak swaps and $300 caps.

Figure 4: Baseload Swap Prices (2005-2019, nominal dollars)



Source: ASX.

Figure 5: $300 Cap prices (2005-2019, nominal dollars)

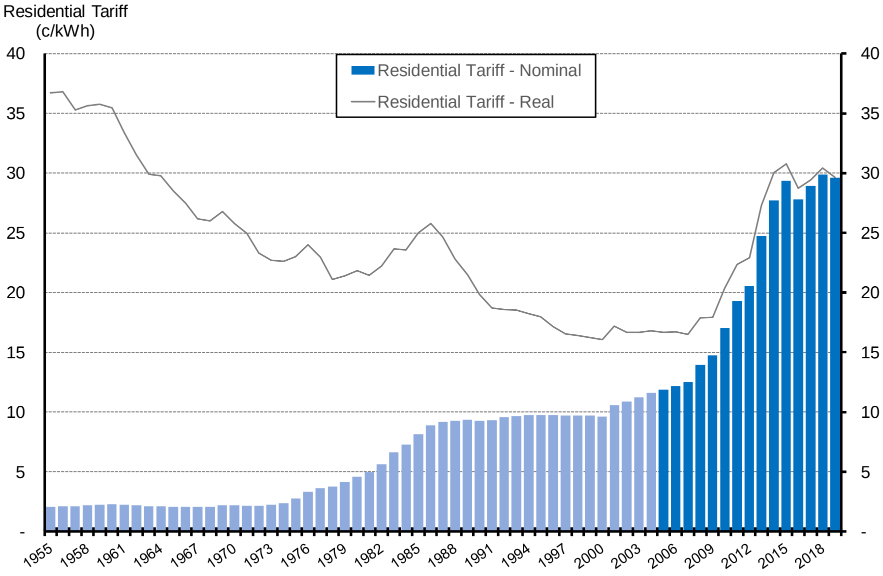


Source: ASX.

3.1.4. Retail Tariffs, Discounts & Switching Rates

For context, the history of QLD Residential Tariffs (1954/55-2018/19) are presented in Figure 6. The period of this research (i.e. dark blue bars, 2004/05-2018/19) is characterised by steep rises, particularly over the period 2006/07-2014/15. A sharp run-up in network tariffs, from ~5.5c/kWh to 15+c/kWh in 2015 before falling back to 11.5c/kWh in 2019 was the main driver of prices changes. While network tariffs contracted over the period 2016-2019, wholesale prices surged and offset network savings. These tariff increases combined with generous Feed-in Tariffs and falling solar PV installation costs led to world-leading rooftop solar PV installation rates – the impact of which is subsequently revealed in Figures 9-10.

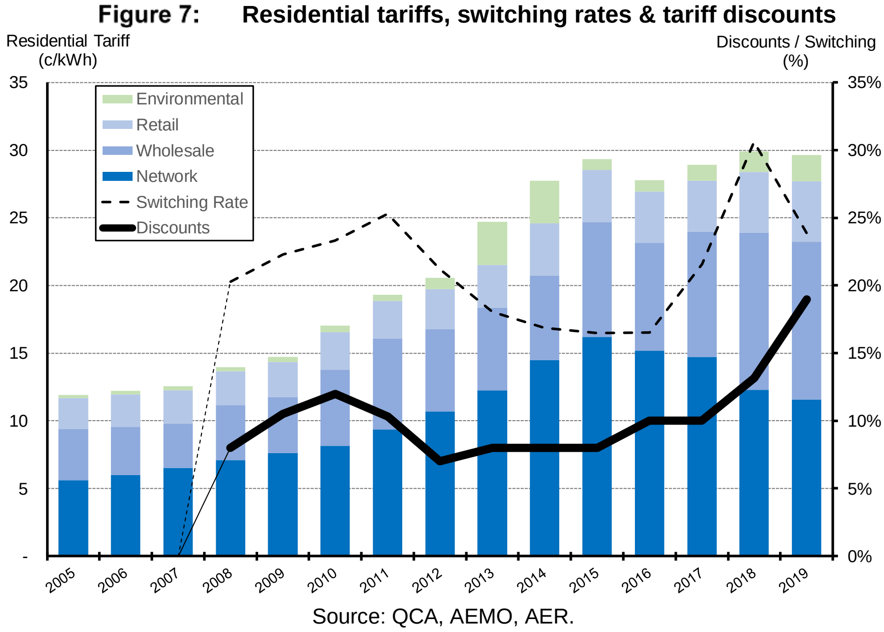
Figure 6: QLD Residential Tariffs (1955-2019)



Source: ESAA, QCA, ABS.

Full Retail Competition did not commence in QLD until 2007. From the outset of contestability, customer switching rates averaged 21.4% per annum. A series of capricious regulatory decisions from 2011-2013 reduced Retail profits, damaged competition (i.e. 2^{nd} tier Retailers exiting), compressed discounting – all of which lowered customer switching rates (Simshauser, 2018). The market was deregulated in 2016 following which competition increased along with the level of discounting. For modelling purposes strong and weak segment tariffs and customer numbers are combined to a blended average.[37]

Figure 7: Residential tariffs, switching rates & tariff discounts



Source: QCA, AEMO, AER.

3.1.5. Retail Load

Table 5 and Figure 8 provide an overview of Retail load, split by Mass Market and Commercial & Industrial segments. Average Residential Load (column 4) rises from 7,366 to 7,824kWh by 2009/10, then declines to 5,598kWh by 2018/19. The driver of

[37] The two-year average customer switching rate from Figure 7 is multiplied by prevailing tariff discounts in Figure 7, with this result deducted from the Default Tariff. This has the effect of capturing the average price sold to both strong and weak retail segments based on an implicit assumption that discounted contracts have a two-year duration – after which the customer reverts to the Default Tariff.

the initial rise in load is uptake of air-conditioning units, while the decline is driven by the uptake of solar PV.[38]

Table 5: Retail Customer Load (2004/05-2018-19)

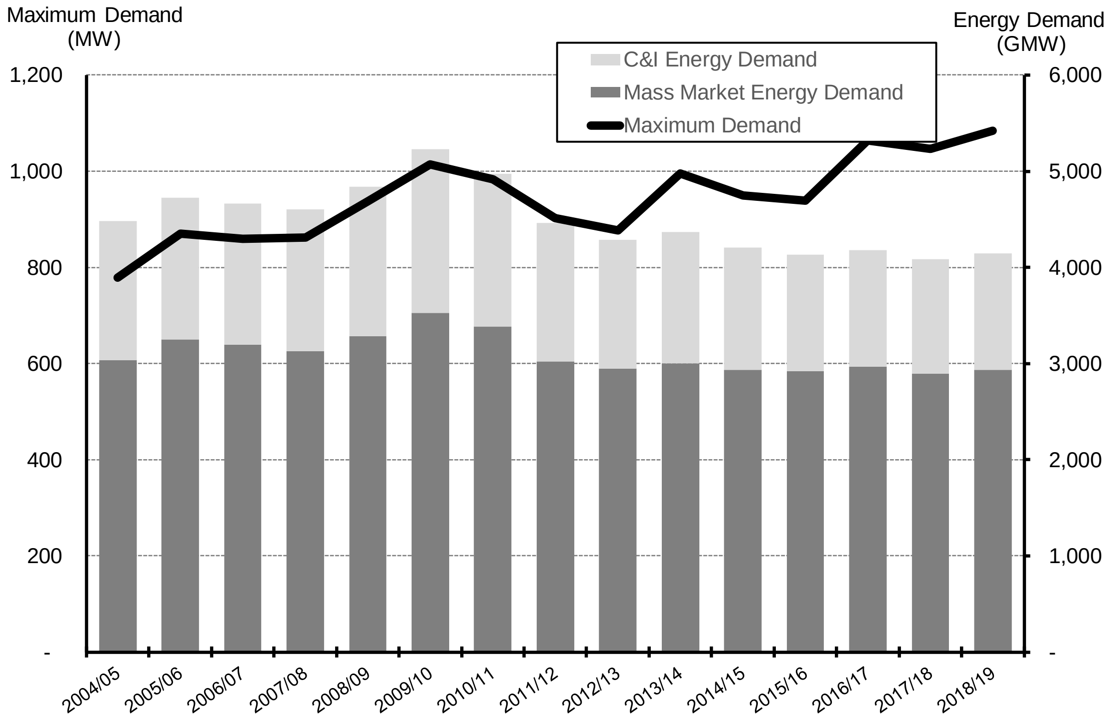
Fin Year	Observations	Mass Market* Customer Numbers^	Average Residential Load*	Total Mass Market Energy Demand	Commercial & Industrial Demand	Portfolio Energy Demand	Portfolio Maximum Demand	Portfolio Load Factor
	(t)		(kWh)	(GWh)	(GWh)	(GWh)	(MW)	
2004/05	17520	329,419	7,366	3,033	1,452	4,485	778	0.66
2005/06	17520	334,943	7,767	3,252	1,474	4,726	871	0.62
2006/07	17520	339,804	7,519	3,194	1,473	4,667	860	0.62
2007/08	17568	347,263	7,210	3,130	1,474	4,603	863	0.61
2008/09	17520	352,325	7,464	3,287	1,549	4,836	937	0.59
2009/10	17520	360,332	7,824	3,524	1,707	5,231	1,014	0.59
2010/11	17520	365,196	7,410	3,383	1,589	4,971	983	0.58
2011/12	17568	372,261	6,497	3,023	1,440	4,463	903	0.56
2012/13	17520	378,872	6,219	2,945	1,341	4,286	878	0.56
2013/14	17520	382,051	6,280	2,999	1,367	4,366	996	0.50
2014/15	17520	387,671	6,053	2,933	1,276	4,209	950	0.51
2015/16	17568	393,499	5,939	2,921	1,213	4,134	938	0.50
2016/17	17520	399,005	5,947	2,966	1,213	4,179	1,064	0.45
2017/18	17520	405,796	5,699	2,891	1,196	4,087	1,046	0.45
2018/19	17520	419,234	5,598	2,934	1,213	4,147	1,085	0.44

* Mass Market comprises Residential Households and the SME sector. The average SME customer is 3x the size of the average Residential household.

^ Residential customer numbers commence at 288,242 and SME customer numbers commence at 41,177.

Sources: ESAA, AEC, AEMO, QCA.

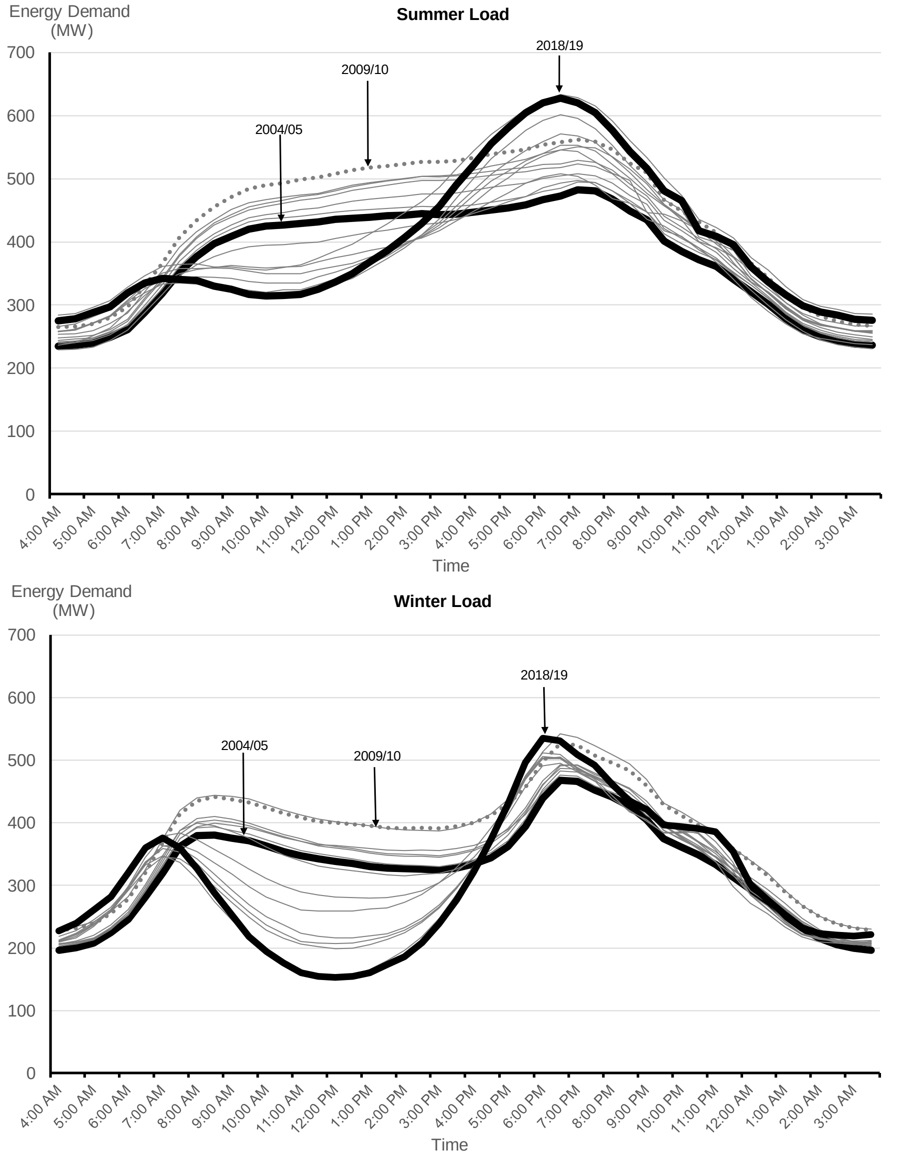
Figure 8: Retail Customer Load (2004/05-2018/19)



The striking feature of the customer book is the ‘twisting’ load shape and load factor deterioration over time. Underpinning this are profound impacts of rooftop solar PV systems on the relative shape of Mass Market load, illustrated in Figures 9-10 for summer and winter. Note the *hollowing out* of load during daylight hours to 2018/19 – winter being particularly pronounced given typically mild daytime weather conditions in QLD.

[38] In QLD, the take-up rate of air conditioning units in 1998 was ~23% but this had risen to 72% in 2010. Similarly, installations of solar PV prior to 2008 was negligible but by 2020 was estimated to be 35.7% of dwellings (see QLD data at https://pv-map.apvi.org.au/historical).

Figure 9: Mass Market Average Summer & Winter Load (2004/05 – 2018/19)



3.2 Modelling Framework

Three sequential models are used, i). Unit Commitment Model for Generation, ii) Retail Portfolio Model, and iii). Dynamic Financial Model. The Unit Commitment and Retail Portfolio Models are operational in nature and computationally intensive given 30-minute resolution over 15 years. 30-minute results are rolled-up into Quarterly outputs and fed into the Dynamic Financial Model, which ultimately produces the Financial Results on an Annual basis.

3.2.1. Unit Commitment Model

The Unit Commitment Model simulates plant dispatch for each of the 262,944 trading intervals over the period 2004/05-2018/19. The Model's objective function is to maximise spread options inherent in spot electricity and gas prices, subject to various OCGT constraints and non-convexities. Essential model inputs include OCGT technical and financial data (Table 1), 30-minute spot prices and daily spot gas prices (Figures 2-3). Model structure is as follows:

Let Y be the ordered set of Years.

$$n \in \{1..|Y|\} \wedge y_n \in Y, \tag{1}$$

Let H be the ordered set of Half-Hour trading intervals in each year n.

$$t \in \{1..|H|\} \wedge h_t \in H, \tag{2}$$

Let $\bar{G}$ be the ordered set of gas turbine units at maximum continuous rating, $\bar{g}_j$.

$$j \in \{1..|\bar{G}|\} \wedge \bar{g}_j \in \bar{G}, \tag{3}$$

Marginal Running Costs include Fuel $F(g_j^t)$ and Variable Operations & Maintenance costs (VOM_j^t). $F(g_j^t)$ is non-convex because of start-up quantity a_j with marginal fuel consumed at the plant's heat rate h_j. Each coefficient is strictly non-negative. p_F^t is the price of Fuel. Once operational, MRC_j^t reduces because Fuel consumed during the start-up sequence (a_j) is sunk.

$$\exists\ \bar{g}_j \middle| MRC_j^t = F(g_j^t) \cdot p_F^t + g_j^t \cdot VOM_j^t \middle| F(g_j^t) = if \begin{cases} g_j^{t-1} = 0, a_j + h_j \cdot g_j^t \\ g_j^{t-1} > 0, h_j \cdot g_j^t, \end{cases} \tag{4}$$

Following unit commitment, quantity generated g_j^t is bounded by maximum rated capacity $\bar{g}_j$ and minimum stable load $\underline{g}_j$.

$$\underline{g}_J < g_j^t < \bar{g}_j\ \forall\ g_j^t > 0, \tag{5}$$

Plant is subject to annual planned outages of one week $(o_{j,u}^t)$, periodic Major Inspections of one month, and forced outages of 6% $(\alpha_{j,u}^t)$ per annum. Planned outages are pre-scheduled in mild seasons. Forced outages (including failed starts) are random, occurring throughout the year. Available capacity is therefore stochastic and modelled at the station level for each trading interval:

$$\sum_{j=1}^{|\bar{G}|} \overline{g}_j^t \mid if \begin{cases} rand[0..1] < \alpha_{j,u}^t \wedge t \neq o_{j,u}^t,\ \overline{g}_j^t \\ rand[0..1] \geq \alpha_{j,u}^t \vee t = o_{j,u}^t, 0, \end{cases} \tag{6}$$

Gas turbines are subject to a start-up sequence(γ_j) which means maximum output in the first trading interval following unit commitment is not feasible:

$$if\ p_e^t > MRC_j^t \wedge g_j^{t-1} \begin{cases} = 0, (\gamma_j \cdot \overline{g}^t) \\ \neq 0, \overline{g}^t, \end{cases} \tag{7}$$

Gas turbines have practical minimum economic run-times. Unit commitment is subject to expected electricity prices p_e^t over a look-ahead period (θ) set to four hours to ensure units are not started for brief periods of marginal value.[39] Conversely, if already operational and marginal value is expected, units remain in service:

$$g_j^t = if \begin{cases} \sum_{\mathrm{t}}^{t+\theta} \frac{p_e^t}{\theta} \geq \mathrm{MRC}_j^t, \overline{g}^t \\ g^{t-1} > 0 \wedge p_e^t \geq \mathrm{MRC}_j^t, \overline{g}^t \\ Otherwise\ 0, \end{cases} \tag{8}$$

[39] The consequence of Eq.(8) is that the station will sometimes start early in anticipation of a major price spike thereby capturing realistic behaviour under uncertainty, and may not generate during brief spikes of low profitability thereby avoiding unnecessary operating hours and/or unit starts. However, subject to Eq.(6) unit commitment will capture major price spikes reflecting an assumption of high quality short-term price forecasting.

In the present exercise, key financial and operational outputs for each trading interval *t* in each year *n* are extracted and rolled-up into an ordered set of quarterly and annual results ($n = 15$).

Generation revenue for year n (R_G^n) is calculated as the sum of spot revenues, Cap sales less Contract-for-Difference payments on Caps:

$$R_G^n = \sum_{j=1}^{|G|} \sum_{t=1}^{|H|} \left(g_j^t \cdot p_e^t \cdot T \right) + \sum_{t=1}^{|H|} [(v_c^n \cdot p_c^n \cdot T) - (max(0, p_e^t - p_s) \cdot v_c^n \cdot T)] \quad (9)$$

where

v_c^n	= volume of Caps (MW)
p_c^n	= price of Caps ($/MWh)
T	= duration of each time period *t* (in hours)
p_s	= strike price of Cap ($/MWh)

Generation plant Marginal Running Costs for year n (MRC_G^n) is calculated as the sum of start-up fuel, fuel used during operations and VOM.

$$MRC_G^n = \sum_{j=1}^{|G|} \sum_{t=1}^{|H|} \left[\left(s_j^t \cdot a_j + h_j \cdot g_j^t \right) \cdot p_F^t + \left(VOM_j^t \cdot g_j^t \right) \right] \Big| if\ s_j^t = \begin{cases} 1, g_j^t > 0\ and\ g_j^{t-1} = 0 \\ 0, \end{cases}, \quad (10)$$

where

s_j^t	= unit starts in each dispatch interval for each unit, *j*

3.2.2. Retail Load Model

The Retail Load Model produces the Retailer's annual revenues and Wholesale Energy Costs for the 262,944 30-minute trading intervals from 2004/05-2018/19. Model structure is as follows:

Let Ψ be the ordered set of customer segments in the portfolio.

$$k \in 1..|\Psi| \wedge \psi_k \in \Psi \wedge \forall \mathrm{k}, \mathrm{m} | \mathrm{k} \neq \mathrm{m}, \mathrm{k} \neq \mathrm{u}, \mathrm{m} \neq \mathrm{u}: \psi_k \cap \psi_m = \{\}, \quad (11)$$

Let Ω be the ordered set of customers within each customer segment:

$$w \in \{1 \ldots |\Omega|\} \wedge \omega_w \in \Omega, \quad (12)$$

For each year n, Retailer Revenues R_R^n are calculated as follows:

$$R_R^n = \left[\sum_{k=1}^{|\Psi|} \sum_{w=1}^{\Omega} \left(\Gamma_f^{k,n} \cdot d^n \right) \right] + \left[\sum_{k=1}^{|\Psi|} \sum_{t=1}^{|H|} \left(\Gamma_r^{k,n} \cdot l_t^k \cdot \left(1 - \delta^{k,n} \right) \right) \right], \quad (13)$$

Where

$\Gamma_f^{k,n}$	= Tariff daily fixed charge for customer segment k
d^n	= the number of billing days
$\Gamma_r^{k,n}$	= Tariff variable rate for customer segment k
l_t^k	= customer segment k's load in trading interval t
$\delta^{k,n}$	= weighted average market contract discounts

Wholesale Energy Costs (W^n) comprise spot market purchases and difference payments on financial instruments (base swaps, peak swaps and caps) and are calculated as follows:

$$W^n = \sum_{t=1}^{H}\left[p_e^t \cdot \sum_{k=1}^{\Psi} l_\psi^t \cdot T\right] + \sum_{t=1}^{H}[(p_e^t - p_b^t)\cdot v_b^t \cdot T] + \sum_{t=1}^{H}\left[\left(p_e^t - p_p^t\right)\cdot v_p^n \cdot T\right] + \sum_{t=1}^{H}[-p_c^n \cdot v_c^n + (p_e^t - p_s)\cdot v_c^n \cdot T], \quad (14)$$

where

v_l^t	= aggregate customer load (MW) in trading interval (t)
v_b^t, v_p^t	= volume of base swaps and peak swaps (MW)
p_b^t, p_p^t	= price of base swaps and peak swaps ($/MWh)

3.2.3. Dynamic Financial Model

The Dynamic Financial Model produces a comprehensive set of financial statements (Profit & Loss, Balance Sheet, Cash Flow, Taxation Schedule, Debt Facility module for corporate debt and for Project Finance). Outputs from the Unit Commitment Model and Retail Load Model feed directly into the Financial Model at Quarterly resolution. Financial Model produces both Quarterly and Annual results. Let $\bar{B}$ be the ordered set of business combinations.

$$\beta \in \{1..|\bar{B}|\} \wedge \bar{b}_\beta \in \bar{B}, \wedge\beta = \{G, R, VI\} | G \cap R = \{\} \wedge VI = G \cup R, \quad (15)$$

- **Generation Profit & Loss**

$$\Pi_G^n = (R_G^n - MRC_G^n - FOM_G^n - d_G^n - I_G^n - \tau_G^n) \wedge EBITDA_G^n = (R_G^n - MRC_G^n - FOM_G^n), \quad (16)$$

where

Π_G^n	= Profit function or Net Profit After Tax (NPAT)
FOM_G^n	= Fixed Operations & Maintenance
d_G^n	= Depreciation & Amortisation
I_G^n	= Financing costs
τ_G^n	= Taxation
$EBITDA_G^n$	= Earnings before Interest, Tax, Depreciation & Amortisation

- **Retail Profit & Loss**

$$\Pi_R^n = (R_R^n - W^n - OE^n - ROC^n - d_R^n - I_R^n - \tau_R^n) \wedge EBITDA_R^n = (R_R^n - W^n - OE^n - N^n - ROC^n), \quad (17)$$

Where

OE^n	= Other Energy Costs relating to wholesale markets[40]
N^n	= Network charges
ROC^n	= Retail Operating Costs[41]

If profits are made, dividend payout ratio $\left(DPR_\beta\right)$ is:

$$Divi_\beta = if\,\Pi_\beta^n \begin{cases} > 0, \Pi_\beta^n \cdot DPR_\beta \\ < 0, 0 \end{cases}, \quad (18)$$

- **Depreciation & Amortisation**

In order to determine values for d_β^n, I_β^n and τ_β^n, Asset Values (i.e. Capital Costs) first need to be defined for Generation $\left(X_G^{n=0}\right)$ and Retail $(X_R^{n=0})$. Upfront and ongoing

[40] These include including renewable program subsidies, technology set-side schemes, carbon taxes, rooftop solar PV Feed-in Tariff Subsidies, Frequency Control Ancillary Services, Market Operator Fees and transmission system losses. In 2004/05 these costs collectively added to $6.78/MWh and by 2018/19 had risen to $31.07/MWh. 80% of the cost increases related to renewable program subsidies (refer Fig.6) with the balance being largely in line with inflation.

[41] These include Retail Operating Costs ($/customer), Marketing Costs (including Customer Retention and Acquisition costs, $/customer), and General & Administrative expenses. Bad debts are also included, at 1% of sales per annum.

Capital costs $\left(X_\beta^n, x_\beta^n\right)$ give rise to tax depreciation (d_β^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0:

$$d_G^n = \left(\frac{X_G^{n=0}}{L}\right) + \left(\frac{\sum_{n=1}^{|Y|} x_G^n}{\sum_{n=1}^{|Y|} L-(n-1)}\right) \wedge d_R^n = \left(\frac{(1-gw_R)\cdot X_R^{n=0}}{L}\right) + \left(\frac{\sum_{n=1}^{|Y|} x_R^n}{\sum_{n=1}^{|Y|} L-(n-1)}\right), \qquad (19)$$

Where

gw_R is assets ascribed to Goodwill and is *not* depreciable.

- **Taxation**

Taxation $\left(\tau_\beta^n\right)$ payable at the corporate taxation rate (τ_c) is applied to $EBITDA_\beta^n$ less Interest $\left(I_\beta^n\right)$ later defined, less d_β^n. To the extent $\left(\tau_\beta^n\right)$ results in non-positive outcome, tax losses $\left(\bar{\tau}_\beta^n\right)$ are carried forward and offset against future periods.

$$\tau_\beta^n = Max(0, \left(EBITDA_\beta^n - I_\beta^n - d_\beta^n - \bar{\tau}_\beta^{n-1}\right). \tau_c) \qquad (20)$$

$$\bar{\tau}_\beta^n = Min(0, \left(EBITDA_\beta^n - I_\beta^n - d_\beta^n - \bar{\tau}_\beta^{n-1}\right). \tau_c) \qquad (21)$$

- **Debt Structuring**

The debt financing module computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. Two types exist (a) BBB-rated Corporate Facilities (CF) (i.e. balance-sheet financings) and (2) Project Financings (PF). Two structures exist – ‘A’ and ‘B’ Facilities (‘Bullet’ and ‘Amortising’, respectively), ‘A’ being semi-permanent with a nominal repayment tenor of 25 years. The decision tree for the two tranches of debt is the same, so for the Debt Tranche where DT = 1 or 2, the calculation is as follows:

$$if\ n \begin{cases} > 1, DT_\beta^n = DT_\beta^{n-1} - P_\beta^{n-1} \\ = 1, DT_\beta^1 = D_\beta^0 . \Phi \end{cases} \qquad (22)$$

D_β^0 refers to the total amount of debt used in the project. The split (Φ) of debt between Facilities refers to the manner in which debt is apportioned to each Tranche. In the model, 35% of debt is assigned to Tranche 1. Principal P_β^{n-1} refers to the amount of principal repayment for tranche *DT* in period *n* and is calculated as an annuity:

$$P_\beta^n = \left(\frac{DT_\beta^n}{\left[\frac{1-(1+\left(R_{T\beta}^z + C_{T\beta}^z\right))^{-n}}{R_{T\beta}^z + C_{T\beta}^z}\right]} \middle| z \begin{cases} = CF \\ = PF \end{cases} \right) \qquad (23)$$

In (23), $R_{T\beta}$ is the relevant interest rate swap and $C_{T\beta}$ is the credit spread or margin relevant to the issued Debt Tranche. Interest costs $\left(I_\beta^n\right)$ are calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_\beta^n = DT_\beta^n \times (R_{T\beta}^z + C_{T\beta}^z) \qquad (24)$$

Total Debt outstanding D_β^n, total Interest I_β^n and total Principle P_β^n are calculated as the sum of the above components for the two debt Tranches. For clarity, Loan Drawings are equal to D_0^n in year 0 to form the initial financing.

- **Debt Sizing**

One of the key calculations is the derivation of D_β^0. This is determined by the product of the gearing level and the initial Capital Cost $\left(X_\beta^{n=0}\right)$. Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by capital markets and project banks for CF (i.e. BBB corporate) and PF (i.e. Project Finance), respectively:

$$if\ \beta \begin{cases} = CF, Min\left(\frac{FFO_\beta^n}{I_\beta^n}\right) \geq \mathbb{C}_{CF}^n \wedge Min\left(\frac{FFO_\beta^n}{D_\beta^n}\right) \geq \not{g}_{CF}^n \forall n \middle| FFO_\beta^n = \left(EBITDA_\beta^n - I_\beta^n - \tau_\beta^n - dWC_\beta^n - x_\beta^n\right) \\ = PF, Min(DSCR_G^n) \geq \mathbb{C}_{PF}^n, \forall n \middle| DSCR_G = \frac{\left(EBITDA_G^n - x_G^n - \tau_G^n\right)}{P_G^n + I_G^n} \end{cases}, \quad (25)$$

Where

FFO_β^n	= Funds From Operations (a Ratings Agency metric)
$\mathbb{C}_{CF}^n, \not{g}_{CF}^n, \mathbb{C}_{PF}^n$	= Credit Metrics (Ratings Agencies & Project Banks)
WC_β^n	= Working Capital (i.e. Cash, Receivables, Deposits, Payables)
$DSCR_G^n$	= Debt Service Cover Ratio (Project Finance)

- **Cash Flow Statement**

Net Cash Flows are comprised of Cash Flows from Operations $\left(CFO_\beta^n\right)$, Investing $\left(CFI_\beta^n\right)$ and Financing $\left(CFF_\beta^n\right)$ activities:

$$CFI_\beta^n = CFO_\beta^n + CFI_\beta^n + CFF_\beta^n \middle| CFO_\beta^n = R_\beta^n - \left(C_\beta^n + dWC_\beta^n + I_\beta^n + \tau_\beta^n\right) \wedge CFI_\beta^n = \left(X_\beta^n + x_\beta^n\right) \wedge CFF_\beta^n = E_\beta^n + D_\beta^n - P_\beta^n - Divi_\beta, \quad (26)$$

where:

C_β^n	= are Cash Operating Costs $\left(MRC_Q^n, FOM_Q^n, W^n, OE^n, ROC^n\right)$
E_β^n	= Funds from the issue of Equities

- **Balance Sheet**

Current and Non-Current Assets $\left(CA_\beta^n, NCA_\beta^n\right)$ and Current and Non-Current Liabilities $\left(CL_\beta^n, NCL_\beta^n\right)$ are as follows:

$$CA_\beta^n = CFF_\beta^n + AR_\beta^n + CD_\beta^n \wedge NCA_\beta^n = X_G^{n=0} + (gw_R \cdot X_R^{n=0}) + \sum_{n=1}^{|Y|} x_\beta^n - \sum_{n=1}^{|Y|} d_\beta^n + [(1 - gw_R) \cdot X_R^{n=0}] \quad (27)$$

$$CL_\beta^n = AR_\beta^n + \left(P_\beta^{n+1} + I_\beta^n/4\right) + \tau_\beta^n \wedge NCL_\beta^n = \left(D_\beta^n - P_\beta^{n+1}\right) \quad (28)$$

Where:

AR_β^n	= Receivables[42]
CD_β^n	= Market Prudential Deposits[43]
AP_β^n	= Payables[44]

And therefore Equity $\left(EQ_\beta^n\right)$ is:

$$EQ_\beta^n = \sum\left(CA_\beta^n, NCA_\beta^n, CL_\beta^n, NCL_\beta^n\right) + \left(\sum_{n=1}^{|Y|} \Pi_\beta^n - \sum_{n=1}^{|Y|} Divi_\beta^n\right) \quad (29)$$

---

[42] Receivables are 90 days for Mass Market Sales and 30 days of C&I Sales, and 42 days for Wholesale Markets transactions.
[43] AEMO Deposits are calculated per the NEM Rules, (i.e. equivalent to the worst 42 days of spot market trade given current volume exposures).
[44] Payables include 30-day terms for Network Costs, all other Fixed Costs and 42 days for Wholesale Markets transactions.

4. Model Results

Combining data and models from Section 3 enables a set of Revenues, Costs and Capital to be produced for three businesses (i.e. Generator, Retailer, Merged entity). The objective of this research is to analyse two key parameters, viz. i). the extent to which costs of the firms are sub-additive, and ii). the financial stability of firms, pre/post boundary changes. In all scenarios, a Retail hedging[45] structure of 'swap to average, cap to maximum' is deployed, noting this is *not* ex post optimal but a reasonable ex ante vanilla trading strategy, uniformly applied regardless of firm boundaries.[46]

4.1 Project Financed Merchant Power Producer

It is worth reviewing the project financed Merchant Power Producer to illustrate 'bankability' or lack thereof (recall Section 2.3). Table 6 presents data necessary to construct a Project Financing based on parameters relevant in 2005 (re-financings in 2009[47] and 2016).

Table 6: Merchant OCGT Project Financing

Project Finance				Debt Sizing Parameters		
- Post Tax Equity (Er)	(%)	12.00		- DSCR	(times)	1.80
Interest Rates in 2004				- Lockup	(times)	1.35
- Term Loan A 12Yr Swap	(%)	6.18		- Default	(times)	1.10
- Term Loan A Spread	(bps)	180		- Term Loan A	(Yrs)	12
- Term Loan B 5Yr Swap	(%)	5.97		- Term Loan B	(Yrs)	5
- Term Loan B Spread	(bps)	140		- Notional amortisation	(Yrs)	25
Refinancings						
- Term Loan A Refi	Yr	2009		- Term Loan B Refi	Yr	2016
- Term Loan A Swap	(%)	5.83		- Term Loan B Swap	(%)	2.52
- Term Loan A Spread	(bps)	457		- Term Loan B Spread	(bps)	213

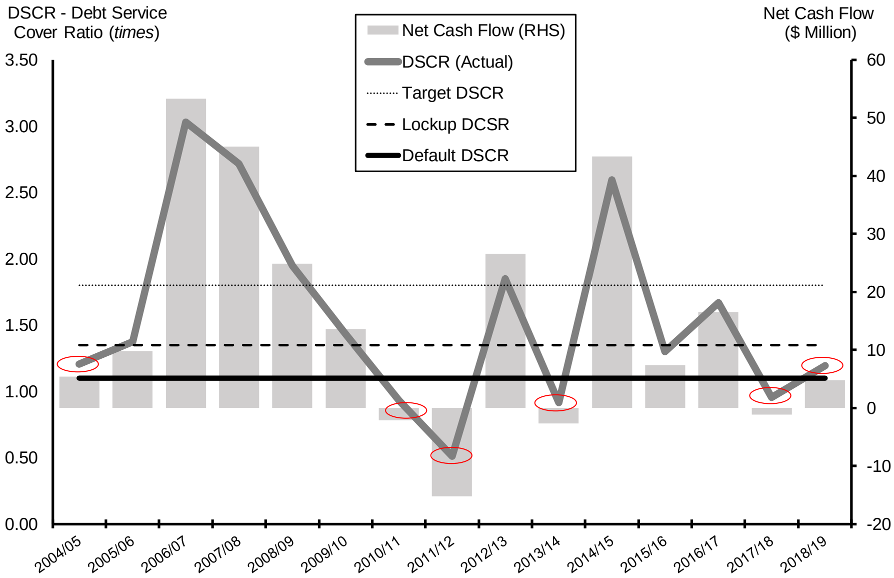
Sources: RBA, (Simshauser, 2009; Simshauser and Gilmore, 2019)

Initial debt sizing is based on Cap prices of $8.28/MWh prevailing in 2004/05 (Fig.5), Debt Service Cover Ratio (DSCR) of 1.8x, and 12-Year Amortising (Term Loan A) and 7-Year Bullet (Term Loan B) Facilities set in semi-permanent structures with a notional 25-year tenor. On this basis, debt-sizing (Eq.25) for the 540MW OCGT plant is $303m or 62% debt (total asset base: $487m). This results in an ex ante minimum expected DSCR of 1.80, estimated post-tax equity IRR of ~14%, and running cash yield to equity of ~12.5%.[48]

Figure 10 illustrates how such a plant would have performed ex post, using historic market data. The plant produces positive cumulative Net Cash Flows (bar chart, RHS Axis) with an average running yield of 8.5% (400bps below the ~12.5% benchmark) and overall average DSCR of 1.59x (vs. initial debt sizing of 1.80x minimum, and overall average of ~1.92). Plant underpinned by spot and short term forward revenues proves too volatile for a Project Finance – with four static insolvency events (Bank Covenant 'Default' DSCR < 1.10) and three static episodes of financial distress (Bank Covenant 'Lockup' DSCR < 1.35) as highlighted by the red circles in Fig.10.[49]

[45] Recall that the hedge portfolio is accumulated over a three-year window (Quarterly quantity resolution, settled every 30 minutes).
[46] To the extent that any profit improvement (or consequential loss) could be initiated by active trader intervention, such gains/losses would also apply to all business combinations in a largely uniform manner.
[47] The refinancing of Term Loan B in 2009 occurs during good electricity market conditions but very tough capital markets conditions (i.e. immediate post-GFC). The facility is assumed to be refinanced for a further 5 years, and refinanced again in 2015 (with the headline interest rate having fallen by a factor of 2, i.e. from 10.4% to 5.0%).
[48] That is, after taking the 2004/05 Cap price and projecting forward at CPI.
[49] Of course in practice, neither event can be taken as 'static'. Financial distress events extend until a full year of covenant compliance has been met, and an insolvency event requires an equity cure, asset sale or reorganisation of debt.

Figure 10: Project Financed Merchant OCGT Plant (2004/05-2018/19)

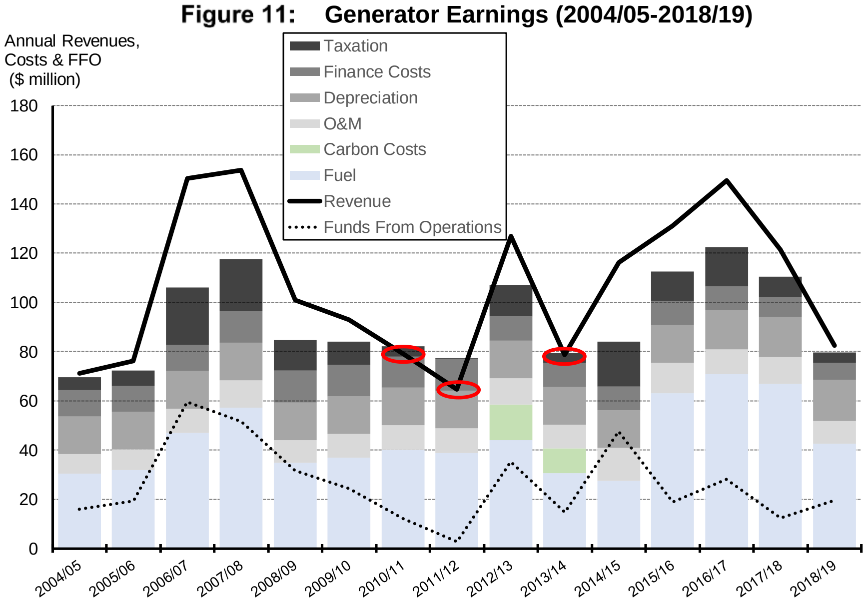


Financial distress events are driven by the combination of price cycles[50] (Fig.2, Fig.5) and operating leverage – the latter a result of the high gearing associated with Project Finance. A different capital structure comprised of corporate finance at gearing levels consistent with investment grade metrics (i.e. ~30% debt) will produce a more tractable set of business results with the amplifying effects of high operating leverage removed, as Section 4.2 demonstrates.

4.2 Stand-alone Generator (Corporate Finance)

Changing the capital structure from Project to Corporate Finance does nothing to subdue pre-finance earnings volatility, but lower gearing does eliminate insolvency events. Figure 11 presents annual Revenues (solid line series), Costs (stacked-bar series) and Funds From Operations or "FFO" per Eq.25 (dotted line series). Three episodes of Statutory Losses occur $[\Pi_Q^n \leq 0, (n = 7,8,10)]$ but given Depreciation is a non-cash item, FFO remains positive in all years.

Figure 11: Generator Earnings (2004/05-2018/19)

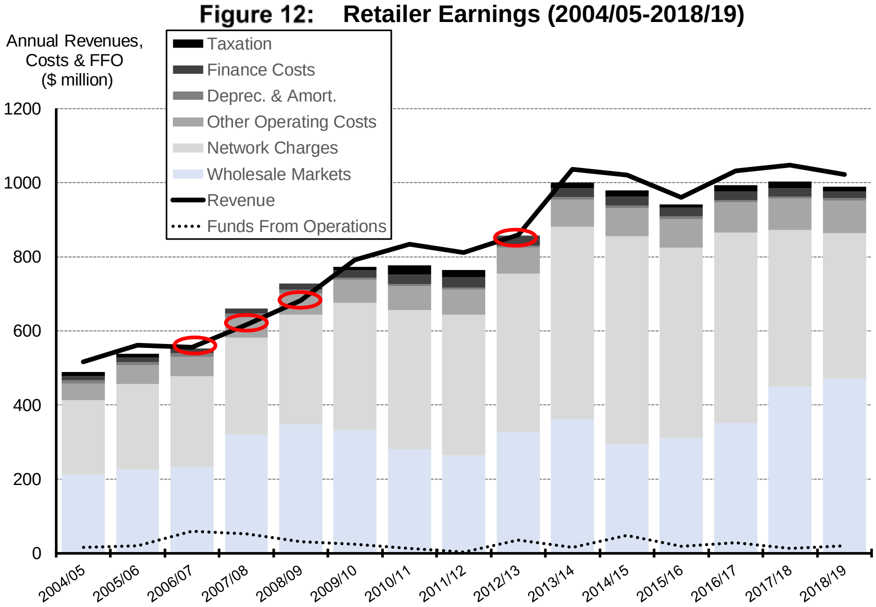


[50] From 2016-2018 a series of Major Inspections are undertaken, each involving $15m capital expenditure. The last of these is primarily responsible for the 2017/18 result but note delaying the capital works by a year would only amplify the 2018/19 result.

4.3 Pure-Play Retailer

The Retailer has a more stable revenue stream than the Generator, but experiences volatility in its wholesale markets purchases as the stacked-bar chart in Fig.12 reveals. The business similarly experiences four episodes of zero or negative earnings $[\Pi_Q^n \leq 0, (n = 3,4,5,9)]$. FFO (dotted line series) remains positive, albeit just, over the 15 year trading history.

Figure 12: Retailer Earnings (2004/05-2018/19)

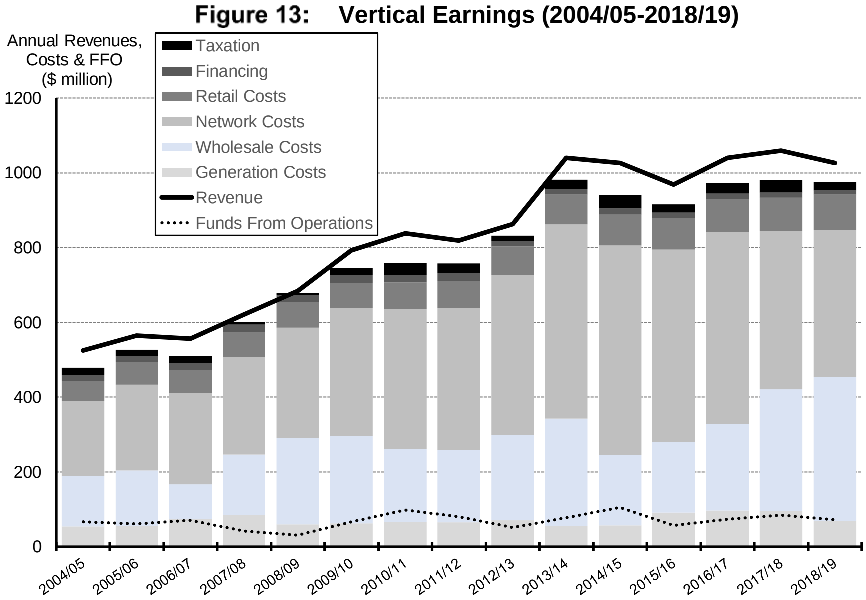


4.4 M&A Event: Vertical Integration

When the two businesses are merged, a series of important outcomes arise. The first is 95.3% of the Generator's on-market transactions are internalised (i.e. forming part of the Retailer's hedge book) and for reasons which become evident (Figs.16-18) the cost of debt finance reduces in line with the credit-standing of the merged entity. All other cost and revenue parameters are otherwise held constant.

Recall that as stand-alone businesses, multiple loss or break-even results were observed $[\Pi_{G,R}^n \leq 0, (n = 3,4,5,7,8,9,10)]$. The merged entity, VI, experiences no such *near misses* either with Profits Π_{VI}^n or FFO_{VI}^n, 2008/09 being the most challenging.

Figure 13: Vertical Earnings (2004/05-2018/19)



These results are worth exploring further by contrasting the variation of Profits and FFO by business combination (Fig.14-15). Note the relative volatility of earnings, Π_{β}^{n}, evident from the box-plots and reported Coefficient of Variation Statistics. The most volatile business combination is the Project Financed Generator, followed by the Pure-Play Retailer. Notice also that the Vertically Integrated firm is the *only* business combination that avoids losses, significantly outperforms a simple Sum-of-the-Parts and has the tightest distribution of Earnings by a considerable margin (Coeff. of Var. at 0.42). To be perfectly clear, the *Sum-of-the-Parts* and *Vertical Integration* are directly comparable – they comprise the exact same businesses but the latter combination has been optimised as noted above.

While the motive for integration is primarily driven by bounded rationality, incomplete markets and asymmetric information, recall from the financial economics literature (Section 2.2) that M&A activity is also optimised when firms have similar earnings volatility, asset complementarity and low earnings correlations (evident in Fig.14) – and thus integration in this instance is entirely predictable from many dimensions. An equivalent set of results applies to FFO_{β}^{n}, which as the next section reveals, is a critical cash flow metric.

Figure 14: NPAT (Π_{β}^{n}) Distribution by Business Combination

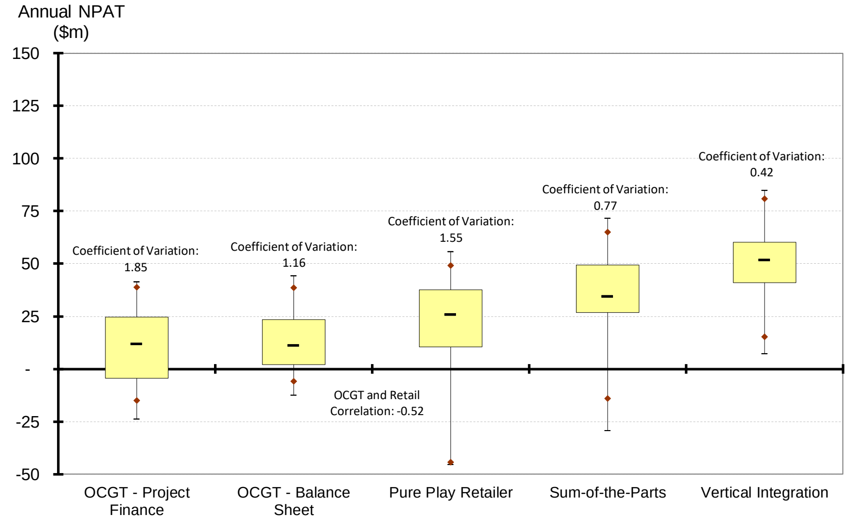
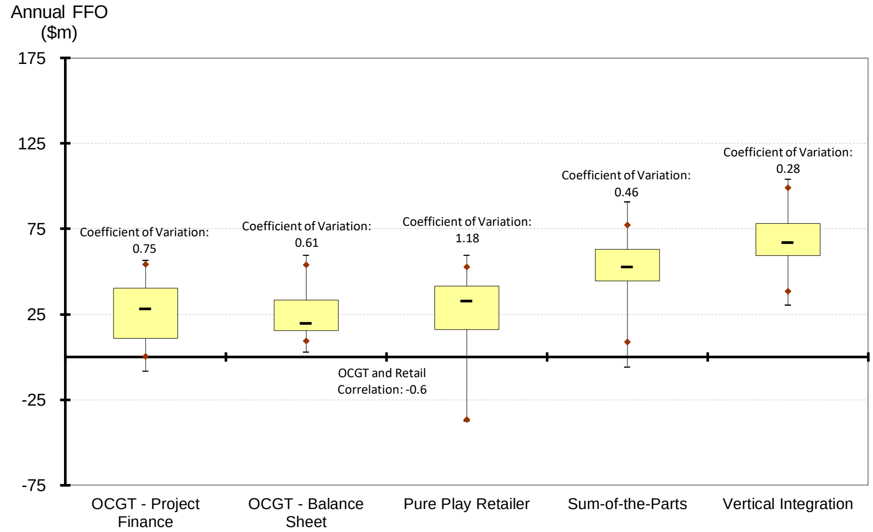


Figure 15: FFO Distribution by Business Combination



4.5 Analysis of credit quality

Of critical importance to the financial stability of firms and the power system more generally is the presence of investment grade credit for reasons set out in Section

2.3 vis-à-vis timely investment (Simshauser, 2010). It is well beyond the scope of this article to undertake a comprehensive review of the credit quality of the business combinations[51], but three ratios provide helpful screening metrics:

Table 7: Credit Ratings Metrics

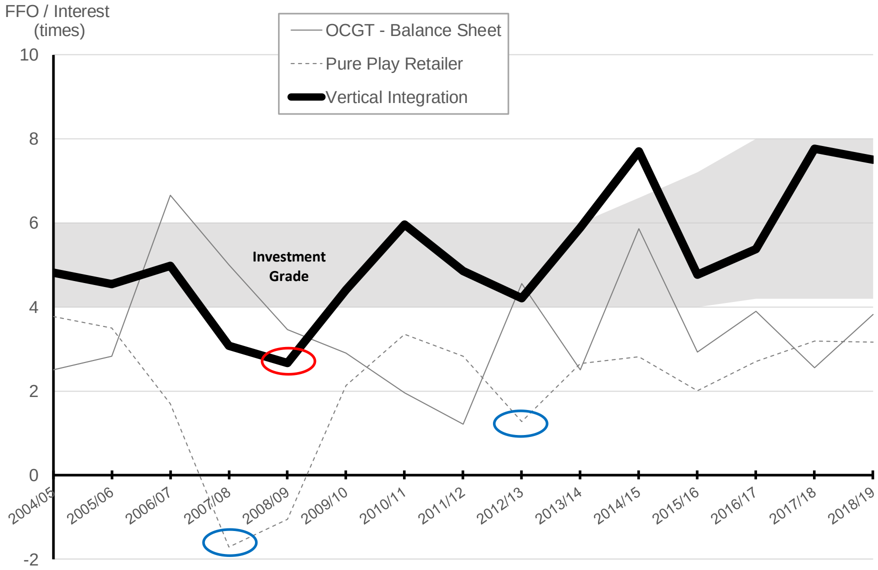
Credit Metric	Investment Grade (BBB)	Sub-Investment Grade
FFO / Interest	≥ 4.0x - 8.0x	< 4.0x
FFO / Debt	≥ 0.19 - 0.35	< 0.20x
Debt / EBITDA	≤4.0x - 2.0x	>4.0x

(Standard & Poor's, 2014; Moody's, 2017a, 2017b)

Comparative results for the Generator, Retailer and Vertically Integrated firm for each metric In Table 7 are illustrated in Figs.16-18, with grey-shaded areas representing 'BBB' credit quality (BBB- being the threshold for investment grade). In Fig.16-17, credit quality is monotonic, whereas in Fig.18 credit quality is nonmonotonic (i.e. a lower result demonstrates enhanced credit standing).

Neither stand-alone Generation nor Retailing exhibit anything like investment-grade credit metrics. The Generator experiences three incursions into investment-grade territory, whereas Retail displays 'junk' quality from Year 2 onwards. Conversely, the Vertically Integrated firm consistently produces investment metrics with one transient excursion across all metrics in 2008/09 (and to a lesser extent, 2007/08) highlighted by the red circles in Fig.16-18. During 2007/08 wholesale prices surged due to a 'millennial drought'. Regulatory lag vis-à-vis regulated Retail Price Caps meant all Retailers experienced difficult trading conditions in 2007/08. These same conditions were ideal for Generators, and consequently a merger displays profoundly positive effects across the three metrics. The 2008/09 and 2012/13 results for Retailers (see blue circles) reflected random and capricious regulated Price Cap determinations (2008/09 being the subject of a successful court challenge, and in 2012/13 a political intervention). In all cases, integration improved overall profitability, credit quality and helped mitigate the worst effects of adverse regulatory outcomes.

Figure 16: FFO/Interest (2004/05-2018/19)



[51] The array of quantitative and qualitative measures is indeed vast (See (Standard & Poor's, 2014; Moody's, 2017a, 2017b) for further details). The most logical manner to analyse the current set of credit results is to assume these business combinations are regional subsidiaries of a larger multi-regional energy utility, and whether the current businesses under consideration are likely to add or subtract to overall credit quality.

Figure 17: FFO/Debt (2004/05-2018/19)

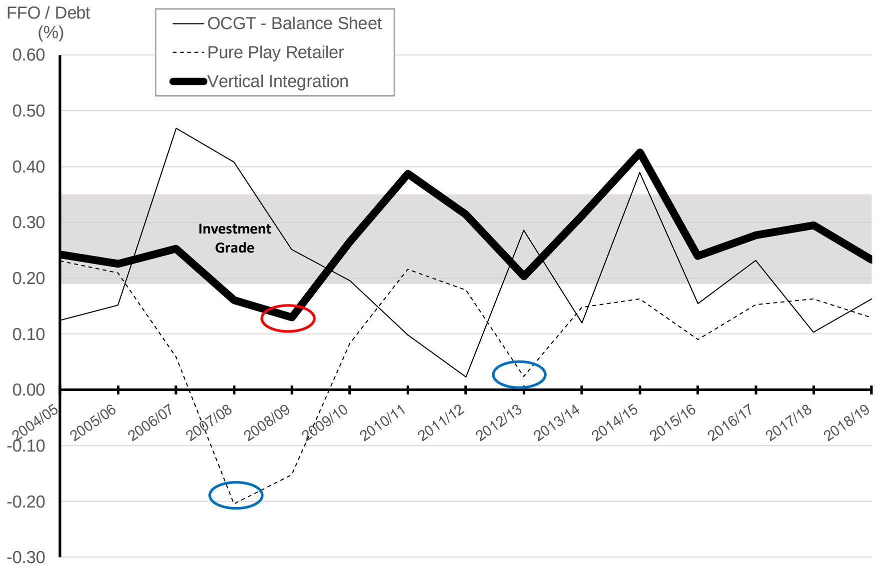
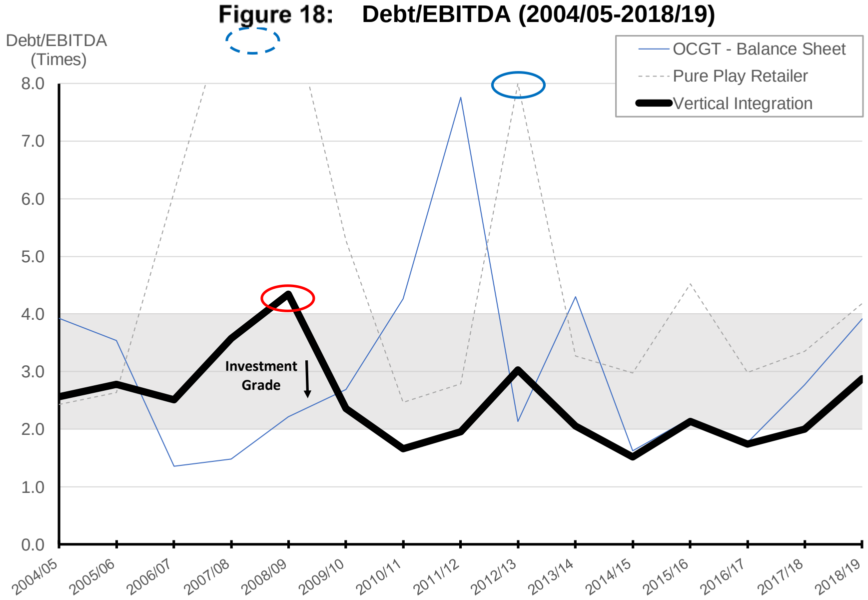


Figure 18: Debt/EBITDA (2004/05-2018/19)



The fact that the Vertical firm experiences a transient excursion outside investment grade territory (i.e. 2008/09) does not mean an automatic downgrade, although ‘negative watch’ would surely arise. Ratings Agencies ‘look through’ transient deterioration in metrics and in my view, the extraordinary trading conditions in 2008/09 would have been accounted for accordingly.

4.6 Economies of Vertical Integration

Analysing the extent to which Generation and Retail have sub-additive costs or *economies of vertical integration* (EVI^n) is based on Eq.30 (Baumol, Panzer and Willig, 1982). A positive value implies economies of integration and a negative value implies diseconomies.

$$\sum_{n=1}^{|Y|} EVI_{VI}^{n} = \left(\sum_{n=1}^{|Y|} \frac{C_{(G,0)}^{n} + C_{(0,R)}^{n} - C_{(VI)}^{n}}{C_{(VI)}^{n}}\right) \qquad (30)$$

Eq.30 is applied to 3 different Cost parameters (Cash Operating Costs, Total Costs, and Total Costs less excess Generation sales) and thee earnings metrics (NPAT, FFO and Economic Returns[52]). Results are presented in Table 8. All measures point to material multi-stage economies of integration. Costs of the Vertical Firm are 15-17% lower than the Sum-Of-The-Parts. Statutory earnings (i.e. NPAT) are up 35% and Credit Quality (FFO) is enhanced by 26%. Economic Returns from the combined entity are greater than either of the stand-alone entities and 25% higher than the Sum-Of-The-Parts. And finally, as Figure 14 illustrated the dispersion of Statutory Profits were reduced by 83% - something which capital markets (and equity capital markets in particular) value.[53]

Table 8: Economies of Vertical Integration (2004/05-2018/19)

Period 2004/05-2018/19	Generation	Retail	Sum-of-the-Parts	Vertical Integration	EVI
Cummulative Costs					
Cash Operating Costs*	839	11,469	12,309	10,734	15%
Total Costs*	1,232	11,881	13,113	11,331	16%
Total Costs* - Gen Sales	1,232	11,881	13,113	11,253	17%
			-		
Cumulative Earnings					
Net Profit After Tax	207	296	503	763	34%
Funds From Operations	394	371	764	1,025	25%
Economic Returns	7.3%	7.2%	7.2%	9.6%	25%
Dispersion of Earnings (Fig.14)					
Coefficient of Variation	1.16	1.53	0.77	0.42	83%

* Cash Operating Costs excludes Depreciation & Amortisation and Finance Costs. Total Costs includes Deprec. & Amort. and Finance Costs.

The Generator's 540MW capacity covered (on average) 64% of the Retailer's peak demand and 23% of energy demand over the 15-year trading window. It was profit maximising to sell any surplus generation capacity into the spot and forward markets and would be unprofitable to withhold this capacity.

The combined business was not optimised per se. The analysis merely merged two random businesses[54] from the QLD region of the NEM. As is often the way with M&As, opportunity reflects what is available, not necessarily what is optimal. Consequently, multi-stage economies of integration could well be significantly higher if a semi-base plant (i.e. CCGT) was also added – scope for further research exists in this regard.

5. Concluding remarks

Should Australian policymakers be concerned with vertically integrated firms in the NEM? To answer this, it is worth reflecting on the starting proposition enshrined within Transaction Cost Economics: vertical integration is an organisational form of last resort (Williamson, 2008). Ultimately, firms prefer market-based transactions until costs exceed the bureaucratic costs of bringing functions in-house. As Stuckey and White (1993) explain, vertical M&As are expensive, risky and particularly hard to unwind. Adjacent segments usually require vastly different skill sets.

It is noteworthy that there are no large unintegrated merchant utilities in Australia's NEM, something that Kwoka (2002) observed in the US almost two decades ago. The practical evidence is that 'cost forces' and 'sequential adaptation' vis-à-vis transaction costs are important in determining merchant utility industrial organisation. Quantitative results from combining a Retailer (c.330,000 mass market customers)

[52] Economic Returns $=\sum_{n=1}^{|Y|}\left(\frac{\hat{\Pi}_{\beta}^{n}}{EQ_{\beta}^{n}}\right) \mid \hat{\Pi}_{\beta}^{n} = \Pi_{\beta}^{n} + \left(0.8 \cdot d_{\beta}^{i}\right)$. Here, depreciation is adjusted downwards by 80% to reflect economic rather than taxation lives.

[53] From a purely practical perspective, the issue here is that when the Board and Executive of a listed firm commit to profit guidance, a tighter distribution of probable earnings means better prospects of delivering against that commitment.

[54] The Retail business is notionally based on AGL Energy's Queensland subsidiary, and the Generator is notionally based on Alinta's OCGT subsidiary.

and Generator (540MW OCGT) demonstrate multi-stage economies of 15-17% vis-à-vis cost efficiencies, a 35% improvement in reportable (statutory) profits, a 26% improvement in credit quality and an 83% improvement in the dispersion of earnings. Little wonder vertical business combinations have formed the dominant model in the NEM.

Vertical integration has provided the means by which to stabilise profits, navigate 'the missing money', mitigate the worst effects of capricious regulatory interventions, maintain investment-grade credit metrics and in turn – the continuity of investment in *timely* new plant capacity given the market for Project Financed merchant plant is largely closed.

Adverse views of vertical practices by policymakers are, in my view, conflating problems of *market power derived from horizontal scale* with an otherwise benign form of industrial organisation initiated to navigate transaction costs, viz. asset specificity, bounded rationality, incomplete markets, capricious regulatory decisions, asymmetric information and uncertainty – all of which present hazards for ex-ante investment commitment, and ex-post performance.

6. References

Allaz, B. and Vila, J. L. (1993) 'Cournot competition, forward markets and efficiency', *Journal of Economic Theory*, 59(1), pp. 1–16. doi: 10.1006/jeth.1993.1001.

Anderson, E. J., Hu, X. and Winchester, D. (2007) 'Forward contracts in electricity markets: The Australian experience', *Energy Policy*, 35(5), pp. 3089–3103. doi: 10.1016/j.enpol.2006.11.010.

Arango, S. and Larsen, E. (2011) 'Cycles in deregulated electricity markets: Empirical evidence from two decades', *Energy Policy*, 39(5), pp. 2457–2466. doi: 10.1016/j.enpol.2011.02.010.

Armstrong, M. (2006) 'Recent Developments in the Economics of Price Discrimination', in Blundell, R., Newey, W., and Persson, T. (eds) *Advances in Economics and Econometrics*. Cambridge: Cambridge University Press, pp. 97–141.

Armstrong, M. (2008) 'Price Discrimination', in Buccirossi, P. (ed.) *Handbook of Antutrust Economics*, pp. 433–456.

Arocena, P. (2008) 'Cost and quality gains from diversification and vertical integration in the electricity industry: A DEA approach', *Energy Economics*, 30(1), pp. 39–58. doi: 10.1016/j.eneco.2006.09.001.

Bain, J. (1956) *The Barriers to New Competition*. Cambridge MA: Harvard University Press.

Bajo-Buenestado, R. (2017) 'Welfare implications of capacity payments in a price-capped electricity sector: A case study of the Texas market (ERCOT)', *Energy Economics*, 64, pp. 272–285. doi: 10.1016/j.eneco.2017.03.026.

Barron, J. M. and Umbeck, J. R. (1984) 'The Effects of Different Contractual Arrangements: The Case of Retail Gasoline Markets', *The Journal of Law and Economics*, 27(2), pp. 313–328. doi: 10.1086/467067.

Batlle, C. and Pérez-Arriaga, I. J. (2008) 'Design criteria for implementing a capacity mechanism in deregulated electricity markets', *Utilities Policy*, 16(3), pp. 184–193. doi: 10.1016/j.jup.2007.10.004.

Baumol, W. ., Panzer, J. C. and Willig, R. D. (1982) *Contestable Markets and the Theory of Industry Structure*. New York: Hartcourt Brace Jovanovich.

Besser, J. G., Farr, J. G. and Tierney, S. F. (2002) 'The political economy of long-term generation adequacy: Why an ICAP mechanism is needed as part of standard market design', *Electricity Journal*, 15(7), pp. 53–62. doi: 10.1016/S1040-6190(02)00349-4.

Bidwell, M. and Henney, A. (2004) 'Will Neta ensure generation adequacy', *Power UK*, 122(April), pp. 10–26.

Boiteux, M. (1949) 'La tarification des demandes en pointe: Application de la theorie de la vente au cout marginal in Revue Generale de l'Electricite - translated by H Izzard (1960)', *Journal of Business*, 33(2), pp. 157–180.

Booth, R. (2000) *Warring Tribes: the Story of Power Development in Australia*. Perth: Bardak

Group.

Borenstein, B. S., Bushnell, J. B. and Wolak, F. A. (2002) ‘Measuring Market Inefficiencies in California’s Restructured Wholesale Electricity Market’, *The American Economic Review*, 92(5), pp. 1376–1405.

Boroumand, R. H. and Zachmann, G. (2012) ‘Retailers’ risk management and vertical arrangements in electricity markets’, *Energy Policy*, 40(1), pp. 465–472. doi: 10.1016/j.enpol.2011.10.041.

Bublitz, A. *et al.* (2019) ‘A survey on electricity market design : Insights from theory and real-world implementations of capacity remuneration mechanisms’, *Energy Economics*, 80, pp. 1059–1078. doi: 10.1016/j.eneco.2019.01.030.

Bushnell, J. (2004) ‘California’s electricity crisis: A market apart?’, *Energy Policy*, 32(9), pp. 1045–1052. doi: 10.1016/j.enpol.2003.11.003.

Bushnell, J. B., Mansur, E. T. and Saravia, C. (2008) ‘Vertical arrangements, market structure, and competition: An analysis of restructured US electricity markets’, *American Economic Review*, 98(1), pp. 237–266. doi: 10.1257/aer.98.1.237.

Caplan, E. (2012) ‘What drives new generation construction?’, *The Electricity Journal*, 25(6), pp. 48–61.

Carlton, D. W. (1979) ‘Vertical Integration in Competitive Markets Under Uncertainty’, *The Journal of Industrial Economics*, 27(3), pp. 189–209. doi: 10.2307/2098317.

Cepeda, M. and Finon, D. (2011) ‘Generation capacity adequacy in interdependent electricity markets’, *Energy Policy*, 39(6), pp. 3128–3143. doi: 10.1016/j.enpol.2011.02.063.

Chao, H. P., Oren, S. and Wilson, R. (2008) ‘Reevaluation of vertical integration and unbundling in restructured electricity markets’, in *Competitive Electricity Markets*, pp. 27–64. doi: 10.1016/B978-008047172-3.50005-2.

Chemmanur, T. J. and John, K. (1996) ‘Optimal incorporation, structure of debt contracts, and limited-recourse project financing’, *Journal of Financial Intermediation*, 5(4), pp. 372–408. doi: 10.1006/jfin.1996.0021.

Chester, L. (2006) ‘The conundrums facing Australia’s National Electricity Market’, *Economic Papers*, 25(4), pp. 362–377.

Chipty, T. (2001) ‘Vertical Integration , Market Foreclosure , and Consumer Welfare in the Cable Television Industry’, *The American Economic Review*, 91(3), pp. 428–453.

Christensen, L. R. and Greene, W. H. (1976) ‘Economies of Scale in US Electric Power Generation’, *Journal of Political Economy*, 84(4), pp. 655–676.

Coase, R. H. (1937) ‘The Nature of the Firm’, *Economica*, 4(16), pp. 386–405. doi: 10.1111/j.1468-0335.1937.tb00002.x.

Cooper, J. C. *et al.* (2005) ‘Vertical antitrust policy as a problem of inference’, *International Journal of Industrial Organization*, 23, pp. 639–664. doi: 10.1016/j.ijindorg.2005.04.003.

Cramton, P., Ockenfels, A. and Stoft, S. (2013) ‘Capacity market fundamentals’, *Economics of Energy & Environmental Policy*, 2(2), pp. 1–21.

Cramton, P. and Stoft, S. (2005) ‘A Capacity Market that Makes Sense’, *The Electricity Journal*, 18(7), pp. 43–54.

Cramton, P. and Stoft, S. (2006) *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO ’ s Resource Adequacy Problem*. 06–007.

Cramton, P. and Stoft, S. (2008) ‘Forward reliability markets: Less risk, less market power, more efficiency’, *Utilities Policy*, 16(3), pp. 194–201. doi: 10.1016/j.jup.2008.01.007.

Doorman, G. L. (2000) *Peaking capacity in restructured power systems*. Norwegian University of Science and Technology.

Fairman, J. and Scott, J. (1977) ‘Transmission, Power Pools, and Competition in the Electric Utility Industry’, *Hastings Law Journal*, 28(5), pp. 1159–1206.

Von der Fehr, N.-H. and Harbord, D. (1995) ‘Capacity investment and long-run efficiency in market-based electricity industries.’, in Olsen, O. (ed.) *Competition in the electricity supply industry – experience from Europe and the United States*. DJ0F Publishing, Copenhagen.

Fetz, A. and Filippini, M. (2010) ‘Economies of vertical integration in the Swiss electricity sector’, *Energy Economics*, 32(6), pp. 1325–1330. doi: 10.1016/j.eneco.2010.06.011.

Finon, D. (2008) ‘Investment risk allocation in decentralised electricity markets. The need of long-term contracts and vertical integration’, *OPEC Energy Review*, 32(2), pp. 150–183. doi:

10.1111/j.1753-0237.2008.00148.x.

Finon, D. and Pignon, V. (2008) 'Electricity and long-term capacity adequacy: The quest for regulatory mechanism compatible with electricity market', *Utilities Policy*, 16(3), pp. 143–158. doi: 10.1016/j.jup.2008.01.002.

Flannery, M. J., Houston, J. F. and Venkataraman, S. (1993) 'Financing Multiple Investment Projects', *Financial Management*, 22(2), pp. 161–172. doi: 10.2307/3665867.

Fraquelli, G., Piacenza, M. and Vannoni, D. (2005) 'Cost savings from generation and distribution with an application to Italian electric utilities', *Journal of Regulatory Economics*, 28(3), pp. 289–308. doi: 10.1007/s11149-005-3959-x.

Gans, J. S. and Wolak, F. A. (2011) 'A Comparison of Ex Ante versus Ex Post Vertical Market Supply: Evidence from the Electricity Supply Industry', *SSRN Electronic Journal*, (February). doi: 10.2139/ssrn.1288245.

Gilsdorf, K. (1995) 'Testing for Subadditivity of Vertically Integrated Electric Utilities', *Southern Economic Journal*, 62(1), p. 126. doi: 10.2307/1061381.

Godofredo, G., de Bragança, F. and Daglish, T. (2017) 'Investing in vertical integration: electricity retail market participation', *Energy Economics*, 67, pp. 355–365. doi: 10.1016/j.eneco.2017.07.011.

Green, J. (1986) 'Vertical Integration and Assurance of Market', in Stiglitz, J. and Matthewson, F. (eds) *New Developments in the Analysis of Market Structure,*. SpringerLink, pp. 177–207.

Green, R. (1999) 'The Electricity Contract Market in England and Wales', *The Journal of Industrial Economics*, 47(1), pp. 107–124.

Green, R. (2006) 'Market power mitigation in the UK power market', *Utilities Policy*, 14(2), pp. 76–89. doi: 10.1016/j.jup.2005.09.001.

Grossman, S. J. and Hart, O. D. (1986) 'The Costs and Benefits of Ownership: A Theory of Vertical and Lateral Integration', *Journal of Political Economy*, 94(4), pp. 691–719. doi: 10.1086/261404.

Grubb, M. and Newbery, D. (2018) 'UK electricity market reform and the energy transition: Emerging lessons', *Energy Journal*, 39(6), pp. 1–25. doi: 10.5547/01956574.39.6.mgru.

Gugler, K., Liebensteiner, M. and Schmitt, S. (2017) 'Vertical disintegration in the European electricity sector: Empirical evidence on lost synergies', *International Journal of Industrial Organization*. Elsevier B.V., 52, pp. 450–478. doi: 10.1016/j.ijindorg.2017.04.002.

Guo, H. *et al.* (2020) 'Constraining the oligopoly manipulation in electricity market: A vertical integration perspective', *Energy*, 194, p. 116877. doi: 10.1016/j.energy.2019.116877.

Hart, O. and Moore, J. (1990) 'Property Rights and the Nature of the Firm', *Journal of Political Economy*, 98(6), pp. 1119–1158. doi: 10.1086/261729.

Hayashi, P. M., Goo, J. Y.-J. and Chamberlain, W. C. (1997) 'Vertical Economies: The Case of U. S. Electric Utility Industry, 1983-87', *Southern Economic Journal*, 63(3), p. 710. doi: 10.2307/1061104.

Helm, D. (2014) *The return of the CEGB? Britain's central buyer model*, *Energy Futures Network Paper No.4*. doi: 10.7251/pol1408113s.

Hirth, L., Ueckerdt, F. and Edenhofer, O. (2016) 'Why wind is not coal: On the economics of electricity generation', *Energy Journal*, 37(3), pp. 1–27. doi: 10.5547/01956574.37.3.lhir.

Hoecker, J. J. (1987) 'Used and Useful: Autopsy of a Ratemaking Policy', *Energy Law Journal*, 8(303), pp. 303–335.

Hogan, S. and Meade, R. (2007) *Vertical Integration and Market Power in Electricity Markets*, *SSRN Electronic Journal*. doi: 10.2139/ssrn.3354990.

Hogan, W. W. (2005) *On an 'Energy Only' Electricity Market Design for Resource Adequacy*, *Cener for Business and Government - John F. Kennedy School of Government*. Available at: https://ferc.gov/EventCalendar/Files/20060207132019-Hogan_Energy_Only_092305.pdf.

Hogan, W. W. (2013) 'Electricity scarcity pricing through operating reserves', *Economics of Energy and Environmental Policy*, 2(2), pp. 65–86. doi: 10.5547/2160-5890.2.2.4.

Holmström, B. and Roberts, J. (1998) 'The Boundaries of the Firm Revisited', *The Journal of Economic Perspectives*, 12(4), pp. 73–94.

Homberg, F., Rost, K. and Osterloh, M. (2009) 'Do synergies exist in related acquisitions? A meta-analysis of acquisition studies', *Review of Managerial Science*, 3(2), pp. 75–116. doi: 10.1007/s11846-009-0026-5.

Hotelling, H. (1938) 'The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates', *Econometrica*, 6(3), pp. 242–269.

Howell, B., Meade, R. and O'Connor, S. (2010) 'Structural separation versus vertical integration: Lessons for telecommunications from electricity reforms', *Telecommunications Policy*, 34(7), pp. 392–403. doi: 10.1016/j.telpol.2010.05.003.

Huettner, D. A. and Landon, J. H. (1978) 'Electric Utilities : Scale Economies and Diseconomies', *Southern Economic Journal*, 44(4), pp. 883–912.

Hunt, S. and Shuttleworth, G. (1996) *Competition and choice in electricity*. New York: John WIley & Sons.

Jara-Díaz, S., Ramos-Real, F. J. and Martínez-Budría, E. (2004) 'Economies of integration in the Spanish electricity industry using a multistage cost function', *Energy Economics*, 26(6), pp. 995–1013. doi: 10.1016/j.eneco.2004.05.001.

Joskow, P. L. (1987) 'Productivity Growth and Technical Change in the Generation of Electricity', *The Energy Journal*, 8(1), pp. 17–38. doi: 10.5547/issn0195-6574-ej-vol8-no1-2.

Joskow, P. L. (2006) *Competitive electricity markets and investment in new generating capacity*. 06–009.

Joskow, P. L. (2008) 'Capacity payments in imperfect electricity markets: Need and design', *Utilities Policy*, 16(3), pp. 159–170. doi: 10.1016/j.jup.2007.10.003.

Joskow, P. L. (2010) 'Vertical integration', *The Antitrust Bulletin*, 55(3), pp. 545–586.

Kahn, E. and Joskow, P. L. (2002) 'A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000', *The Energy Journal*, 23(4), pp. 1–35.

Kaserman, D. L. and Mayo, J. W. (1991) 'The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Industry', *The Journal of Industrial Economics*, 39(5), pp. 483–502.

Kellow, A. (1996) *Transforming Power – the Politics of Electricity Planning*. Cambridge: Cambridge University Press.

Keppler, J. H. (2017) 'Rationales for capacity remuneration mechanisms : Security of supply externalities and asymmetric investment incentives', *Energy Policy*, 105(September 2016), pp. 562–570. doi: 10.1016/j.enpol.2016.10.008.

Kwoka, J. E. (2002) 'Vertical economies in electric power: Evidence on integration and its alternatives', *International Journal of Industrial Organization*, 20(5), pp. 653–671. doi: 10.1016/S0167-7187(00)00114-4.

Kwoka, J. and Pollitt, M. (2010) 'Do mergers improve efficiency? Evidence from restructuring the US electric power sector', *International Journal of Industrial Organization*, 28(6), pp. 645–656. doi: 10.1016/j.ijindorg.2010.03.001.

Lafontaine, F. and Slade, M. (2007) 'Vertical integration and firm boundaries: The evidence', *Journal of Economic Literature*, 45(3), pp. 629–685. doi: 10.1257/jel.45.3.629.

Landon, J. h (1983) 'Theories of vertical integration and their application to the electric utility industry', *The Antitrust Bulletin*, 28(1), pp. 101–130. doi: 10.1525/sp.2007.54.1.23.

Leautier, T. O. (2016) 'The visible hand: Ensuring optimal investment in electric power generation', *Energy Journal*, 37(2), pp. 89–109. doi: 10.5547/01956574.37.2.tlea.

Leland, H. E. (2007) 'Financial synergies and the optimal scope of the firm: Implications for mergers, spinoffs, and structured finance', *Journal of Finance*, 62(2), pp. 765–807. doi: 10.1111/j.1540-6261.2007.01223.x.

Malmgren, H. B. (1961) 'Information , Expectations and the Theory of the Firm', *The Quarterly Journal of Economics*, 75(3), pp. 399–421.

Mansur, E. T. (2007) 'Upstream competition and vertical integration in electricity markets', *Journal of Law and Economics*, 50(1), pp. 125–156. doi: 10.1086/508309.

Martin, S., Normann, H. and Snyder, C. M. (2001) 'Vertical Foreclosure in Experimental Markets', *The RAND Journal of Economics*, 32(3), pp. 466–496.

Meade, R. (2005) 'Electricity investment and security of supply in liberalized electricity systems', in Mielczarski, W. (ed.) *Development of electricity markets*.

Meade, R. and O'Connor, S. (2009) *Comparison of long-term contracts and vertical integration in decentralized electricity markets*, *Comparison of Long-Term Contracts and Vertical Integration in Decentralised Electricity Markets*. RSCAS 2009/16.

Meyer, R. (2012a) 'Economies of scope in electricity supply and the costs of vertical separation for different unbundling scenarios', *Journal of Regulatory Economics*, 42(1), pp. 95–114. doi: 10.1007/s11149-011-9166-z.

Meyer, R. (2012b) ‘Vertical economies and the costs of separating electricity supply - A review of theoretical and empirical literature’, *Energy Journal*, 33(4), pp. 161–185. doi: 10.5547/01956574.33.4.8.

Michaels, R. J. (2007) ‘Vertical Integration and the Restructuring of the U.S. Electricity Industry’, *Policy Analysis*, 572(April), pp. 1–31. doi: 10.2139/ssrn.595565.

Milstein, I. and Tishler, A. (2019) ‘On the effects of capacity payments in competitive electricity markets : Capacity adequacy , price cap , and reliability’, *Energy Policy*, 129(November 2018), pp. 370–385. doi: 10.1016/j.enpol.2019.02.028.

Modigliani, F. and Miller, M. (1958) ‘The Cost of Capital, Corporation Finance and the Theory of Investment’, *The American Economic Review*, 48(3), pp. 261–297. doi: 10.2307/2220605.

Moody’s (2017a) *Key Ratios by Rating and Industry for Global Non-Financial Corporate: Dec-16*. Available at: https://www.researchpool.com/download/?report_id=1537315&show_pdf_data=true.

Moody’s (2017b) *Rating Methodology: Unregulated Utilities and Unregulated Power Companies*. New York.

Moore, C. G. (1975) ‘Has Electricity Regulation Resulted in Higher Prices? an Econometric Evaluation Utilizing a Calibrated Regulatory Input Variable’, *Economic Inquiry*, 13(2), pp. 207–220. doi: 10.1111/j.1465-7295.1975.tb00988.x.

Mullin, J. C. and Mullin, W. P. (1997) ‘United states steel’s acquisition of the great northern ore properties: Vertical foreclosure or efficient contractual governance?’, *Journal of Law, Economics, and Organization*, 13(1), pp. 74–100. doi: 10.1093/oxfordjournals.jleo.a023383.

Nelson, J. and Simshauser, P. (2013) ‘Is the Merchant Power Producer a broken model?’, *Energy Policy*, 53, pp. 298–310. doi: 10.1016/j.enpol.2012.10.059.

Nelson, T. *et al.* (2019) ‘Efficient integration of climate and energy policy in Australia ’ s National Electricity Market’, *Economic Analysis and Policy*, 64, pp. 178–193. doi: 10.1016/j.eap.2019.08.001.

Nemoto, J. and Goto, M. (2004) ‘Technological externalities and economies of vertical integration in the electric utility industry’, *International Journal of Industrial Organization*, 22(1), pp. 67–81. doi: 10.1016/S0167-7187(03)00091-2.

Neuhoff, K. and De Vries, L. (2004) ‘Insufficient incentives for investment in electricity generations’, *Utilities Policy*, 12(4), pp. 253–267. doi: 10.1016/j.jup.2004.06.002.

Newbery, D. (2006) *Market design*, *EPRG Working Paper*. EPRG Working Paper No.0515.

Newbery, D. (2016) ‘Missing money and missing markets: Reliability, capacity auctions and interconnectors’, *Energy Policy*, 94(January), pp. 401–410. doi: 10.1016/j.enpol.2015.10.028.

Newbery, D. (2017) ‘Tales of two islands – Lessons for EU energy policy from electricity market reforms in Britain and Ireland’, *Energy Policy*, 105(June 2016), pp. 597–607. doi: 10.1016/j.enpol.2016.10.015.

Newbery, D. M. (1998) ‘Competition , Contracts , and Entry in the Electricity Spot Market’, *The RAND Journal of Economics*, 29(4), pp. 726–749.

Newbery, D. M. (2005) ‘Electricity liberalisation in Britain : The quest for a satisfactory wholesale market design’, *The Energy Journal*, 26(2005), pp. 43–70.

Newbery, D. M. and Pollitt, M. G. (1997) ‘The Restructuring and Privatisation of Britain’s CEGB - was it worth it?’, *The Journal of Industrial Economics*, 45(3), pp. 269–303.

Nillesen, P. H. L. and Pollitt, M. G. (2011) ‘Ownership unbundling in electricity distribution: Empirical evidence from New Zealand’, *Review of Industrial Organization*, 38(1), pp. 61–93. doi: 10.1007/s11151-010-9273-5.

Nillesen, P. and Pollitt, M. (2019) *Ownership Unbundling of Electricity Distribution Networks*, *Energy Policy Research Group Working Paper No.1905, University of Cambridge*.

Ordover, J., Saoloner, G. and Salop, S. (1990) ‘Equilibrium Vertical Foreclosure with Investment’, *The American Economic Review*, 80(1), pp. 127–142. doi: 10.2139/ssrn.15102.

Oren, S. (2003) *Ensuring Generation Adequacy in Competitive Electricity Markets*, *Energy Policy*. EPE007.

Peltzman, S. (1976) *Toward a More General Theory of Regulation*. Working Paper No.133. Stanford, CA.

Peluchon, B. (2003) ‘Is investment in peaking generation assets efficient in a deregulated electricity sector?’, in *Research Symposium on European Electricity Markets*, pp. 1–8.

Pierce, R. J. (1984) ‘The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plant and Excess Capacity', *University of Pennsylvania Law Review*, 132(497), pp. 497–560.

Pollitt, M. G. (2004) 'Electricity reform in Chile: Lessons for developing countries', *Journal of Network Industries*, 5(3–4), pp. 221–262.

Posner, R. A. (1974) 'Theories of Economic Regulation.', *Bell J Econ Manage Sci*, 5(2), pp. 335–358. doi: 10.2307/3003113.

Powell, A. (1993) 'Trading Forward in an Imperfect Market : The Case of Electricity in Britain', *The Economic Journal*, 103(417), pp. 444–453.

Reiffen, D. and Vita, M. (1995) 'Comment: Is there new thinking on Vertical Mergers?', *Antitrist Law Journal*, 63(3), pp. 917–941.

Roques, F. A. (2008) 'Market design for generation adequacy: Healing causes rather than symptoms', *Utilities Policy*, 16(3), pp. 171–183. doi: 10.1016/j.jup.2008.01.008.

Roques, F. A., Newbery, D. M. and Nuttall, W. J. (2005) 'Investment Incentives and Electricity Market Design: the British Experience', *Review of Network Economics*, 4(2), pp. 93–128. doi: 10.2202/1446-9022.1068.

Salinger, M. (1988) 'Vertical Mergers and Market Foreclosure', *The Quarterly Journal of Economics*, 103(2), pp. 345–356.

Salop, B. S. C. and Scheffman, D. T. (1983) 'Raising Rivals' Costs', *American Economic Review*, 73(2), pp. 267–271.

Salop, S. and Scheffman, D. T. (1987) 'Cost-Raising Strategies', *The Journal of Industrial Economics*, 36(1), pp. 19–34.

Schweppe, F. C. *et al.* (1988) *Spot Pricing of Electricity*. US: Kluwer Academic Publishers.

Shepard, A. (1993) 'Contractual Form , Retail Price , and Asset Characteristics in Gasoline Retailing', *The RAND Journal of Economics*, 24(1), pp. 58–77.

Simon, H. A. (1955) 'A Behavioral Model of Rational Choice', *The Quarterly Journal of Economics*, 69(1), pp. 99–118. Available at: http://www.jstor.org/stable/1884852.

Simshauser, P. (2005) 'The Gains From the Microeconomic Reform of the Power Generation Industry in East-Coast Australia', *Economic Analysis and Policy*, 35(1–2), pp. 23–43. doi: 10.1016/S0313-5926(05)50002-X.

Simshauser, P. (2008) 'The dynamic efficiency gains from introducing capacity payments in the national electricity market', *Australian Economic Review*, 41(4), pp. 349–370. doi: 10.1111/j.1467-8462.2008.00512.x.

Simshauser, P. (2009) 'On Emissions Trading, Toxic Debt and the Australian Power Market', *Electricity Journal*, 22(2), pp. 9–29. doi: 10.1016/j.tej.2009.01.007.

Simshauser, P. (2010) 'Vertical integration, credit ratings and retail price settings in energy-only markets: Navigating the Resource Adequacy problem', *Energy Policy*, 38(11), pp. 7427–7441. doi: 10.1016/j.enpol.2010.08.023.

Simshauser, P. (2014) 'From First Place to Last: The National Electricity Market's Policy-Induced "Energy Market Death Spiral"', *Australian Economic Review*, 47(4), pp. 540–562. doi: 10.1111/1467-8462.12091.

Simshauser, P. (2018) 'Price discrimination and the modes of failure in deregulated retail electricity markets', *Energy Economics*, 75(August), pp. 54–70. doi: 10.1016/j.eneco.2018.08.007.

Simshauser, P. (2019a) *Lessons from Australia's national emlectricity Market 1998-2018: the strengths and weaknesses of the reform experience*. EPRG Working Paper 1927, Energy Policy Research Group, University of Cambridge. Available at: https://ideas.repec.org/p/cam/camdae/1972.html.

Simshauser, P. (2019b) 'On the Stability of Energy-Only Markets with Government-Initiated Contracts-for-Differences', *Energies*, 12(13), p. 2566. doi: 10.3390/en12132566.

Simshauser, P. (2020) *Merchant renewables and the valuation of peaking plant in energy-only markets*. EPRG Working Paper 2002, Policy Research Group, University of Cambridge. doi: 10.13140/RG.2.2.25864.98563.

Simshauser, P. and Gilmore, J. (2019) 'On Entry Cost Dynamics in Australia ' s National Electricity Market', *The Energy Journal*, 41(1), pp. 259–285.

Simshauser, P. and Nelson, T. (2012) 'The second-round effects of carbon taxes on power project finance', *Journal of Financial Economic Policy*, 4(2), pp. 104–127. doi: 10.1108/17576381211228970.

Simshauser, P., Tian, Y. and Whish-Wilson, P. (2015) 'Vertical integration in energy-only electricity markets’, *Economic Analysis and Policy*, 48, pp. 35–56. doi: 10.1016/j.eap.2015.09.001.

Slade, M. E. (1998) ‘Beer and the Tie : Did Divestiture of Brewer-Owned Public Houses Lead to Higher Beer Prices ?’, *The Economic Journal*, 108(448), pp. 565–602.

Smith, V. L. (1996) ‘Regulatory Refom in the Electric Power Industry’, *Regluation*, 19(1), pp. 33–46.

Spees, K., Newell, S. A. and Pfeifenberger, J. P. (2013) ‘Capacity markets - Lessons learned from the first decade’, *Economics of Energy and Environmental Policy*, 2(2), pp. 1–26. doi: 10.5547/2160-5890.2.2.1.

Standard & Poor’s (2014) *Key Credit Factors For The Unregulated Power And Gas Industry*.

Stigler, G. J. (1971) ‘The Theory of Economic Regulation’, *Bell J Econ Manage Sci*, 2(1), pp. 3–21.

Stigler, G. J. and Friedland, C. (1962) ‘What Can Regulators Regulate? The Case of Electricity’, *Journal of Law and Economics*, 5(Oct 1962), pp. 1–16.

Stoft, S. (2002) *Power System Economics: Designing Markets for Electricity*. Wiley.

Stuckey, J. and White, D. (1993) ‘When and When Not to Vertically Integrate’, *Sloan Management Review*, 34(3), pp. 71–83.

Teti, E. and Tului, S. (2020) ‘Do mergers and acquisitions create shareholder value in the infrastructure and utility sectors? Analysis of market perceptions’, *Utilities Policy*. Elsevier Ltd, 64(April 2019), p. 101053. doi: 10.1016/j.jup.2020.101053.

Turvey, R. (1964) ‘Marginal Cost Pricing in Practice’, *Economica*, 31(124), pp. 426-432cram. doi: 10.2307/3006575.

Vita, M. G. (2000) ‘Regulatory Restrictions on Vertical Integration and Control: The Competitive Impact of Gasoline Divorcement Policies’, *Journal of Regulatory Economics*, 18(3), pp. 217–233. doi: 10.1023/A:1008150819999.

de Vries, L. and Heijnen, P. (2008) ‘The impact of electricity market design upon investment under uncertainty: The effectiveness of capacity mechanisms’, *Utilities Policy*, 16(3), pp. 215–227. doi: 10.1016/j.jup.2007.12.002.

de Vries, L. J. (2003) ‘The instability of competitive energy-only electricity markets’, in *Research Symposium on European Electricity Markets*, pp. 1–8. Available at: http://www.ecn.nl/fileadmin/ecn/units/bs/Symp_Electricity-markets/b2_4-paper.pdf.

Weiss, L. W. (1973) ‘Antitrust in the Electric Power Industry’, *Journal of Reprints for Antitrust Law and Economics*, 5(3 & 4), pp. 645–686.

Wen, F. S., Wu, F. F. and Ni, Y. X. (2004) ‘Generation capacity adequacy in the competitive electricity market environment’, *International Journal of Electrical Power and Energy System*, 26(5), pp. 365–372. doi: 10.1016/j.ijepes.2003.11.005.

Williamson, O. E. (1971) ‘The Vertical Integration of Production: Market Failure Considerations’, *American Economic Review*, 61(2), pp. 112–123. doi: 10.2307/1816983.

Williamson, O. E. (1973) ‘ORGANIZATIONAL FORMS AND INTERNAL EFFICIENCY Markets Some and Hierarchies’, *The American Economic Review*, 63(2), pp. 316–325.

Williamson, O. E. (1975) *Markets and Hierarchies: Analysis and Antitrust Implications. A study in the Economics of Internal Organization*. New York: Free Press.

Williamson, O. E. (1979) ‘Transaction-Cost Economics: The Governance of Contractual Relations’, *The Journal of Law and Economics*, 22(2), pp. 233–261.

Williamson, O. E. (2008) ‘Outsourcing: Transaction cost economics and supply chain management’, *Journal of Supply Chain Management*, 44(2), pp. 5–16. doi: 10.1111/j.1745-493X.2008.00051.x.

Wood, T., Dundas, G. and Percival, L. (2019) *Power play How governments can better direct Australia’s electricity market*. Grattan Institute - Melbourne.

GENERATOR	PROFIT & LOSS																
Year Index			**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ANNUAL LOAD																	
Generation		MWh	925,524	931,572	1,339,164	1,551,294	926,820	951,048	990,090	951,318	1,058,022	712,368	1,619,244	1,285,524	730,062	857,664	401,058
REVENUES																	
Spot Market Revenue			54.7	64.5	150.9	152.8	62.4	74.8	64.0	40.2	123.4	70.9	153.9	126.9	173.8	87.7	55.8
Contract for Differences / Hedges		$m	16.4	11.7	-0.6	0.9	38.5	18.2	15.1	24.5	3.6	7.8	-37.7	4.1	-24.2	33.7	26.6
Total Sales Revenue		**$m**	71.1	76.2	150.3	153.8	100.9	93.0	79.1	64.7	127.0	78.8	116.3	131.0	149.6	121.4	82.4
EXPENSES																	
Fuel		$m	30.4	31.9	47.0	57.3	34.9	37.0	40.0	38.7	43.9	30.5	27.4	63.1	70.8	67.0	42.6
O&M		$m	8.0	8.3	9.8	11.0	9.2	9.6	10.0	10.0	10.6	9.6	13.4	12.2	10.2	10.9	9.1
Carbon Costs		$m	-	-	-	-	-	-	-	-	14.6	10.0	-	-	-	-	-
Total Expenses		**$m**	38.4	40.2	56.9	68.3	44.1	46.5	50.0	48.8	69.2	50.2	40.8	75.4	81.0	77.9	51.8
EBITDA		**$m**	32.7	36.0	93.4	85.5	56.8	46.5	29.1	15.9	57.8	28.6	75.5	55.6	68.7	43.6	30.6
Depreciation and amortisation		$m	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.8	16.3	16.8
EBIT		**$m**	17.4	20.7	78.1	70.2	41.5	31.2	13.8	0.6	42.5	13.2	60.2	40.3	52.8	27.2	13.8
Financing costs		$m	10.6	10.6	10.5	12.9	12.8	12.8	12.7	13.0	9.9	9.8	9.8	9.8	9.7	8.0	6.9
Taxation			5.2	6.2	23.4	21.1	12.4	9.4	4.1	0.2	12.7	4.0	18.1	12.1	15.9	8.2	4.1
NPAT		**$m**	1.6	3.9	44.1	36.2	16.2	9.0	- 3.1	- 12.5	19.9	- 0.6	32.3	18.5	27.3	11.1	2.7
FFO		**$m**	15.9	19.3	59.5	51.6	31.5	24.4	12.2	2.8	35.2	14.8	47.6	18.8	28.1	12.4	19.6
FFO/I		**FFO/I**	2.5	2.8	6.7	5.0	3.5	2.9	2.0	1.2	4.6	2.5	5.9	2.9	3.9	2.6	3.8
Distributions																	
Dvidend	90%		1.4	3.5	39.7	32.6	14.6	8.1	0.0	0.0	17.9	0.0	29.1	16.6	24.5	10.0	2.5
Retained earnings			0.2	0.4	4.4	3.6	1.6	0.9	-3.1	-12.5	2.0	-0.6	3.2	1.8	2.7	1.1	0.3
Economic Returns			3.9%	4.6%	15.9%	13.5%	7.8%	5.8%	2.5%	-0.1%	9.2%	3.3%	12.7%	8.7%	11.2%	6.7%	4.5%

GENERATOR	BALANCE SHEET			2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ASSETS																		
Current asset															-	-		
	Cash and cash equivalents	$m	19.6	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	38.1	38.1	34.8	34.8
	Trade receivables	$m	7.9	8.2	8.8	17.3	17.7	11.6	10.7	9.1	7.4	14.6	9.1	13.4	15.1	17.2	14.0	9.5
Total current asset		$m	27.5	49.5	50.1	58.6	59.0	52.9	52.0	50.4	48.7	55.9	50.4	54.7	53.2	55.3	48.8	44.3
Non-current asset																		
	Generation Plant	$m	459.0	444.7	429.4	414.0	398.7	383.4	368.0	352.7	337.4	322.0	306.7	291.4	291.0	290.2	288.9	272.0
Total non-current asset		$m	459.0	444.7	429.4	414.0	398.7	383.4	368.0	352.7	337.4	322.0	306.7	291.4	291.0	290.2	288.9	272.0
Total asset		$m	486.5	494.2	479.4	472.6	457.7	436.3	420.0	403.1	386.1	377.9	357.1	346.0	344.2	345.5	337.6	316.3
LIABILITIES																		
Current liability																		
	Trade payables	$m	3.0	3.2	3.3	4.7	5.6	3.6	3.8	4.1	4.0	5.7	4.1	3.4	6.2	6.7	6.4	4.3
	Interest payable	$m	-	2.6	2.6	2.6	3.2	3.2	3.2	3.1	3.2	2.4	2.4	2.4	2.4	2.4	2.0	1.7
	Provision - Taxes	$m	-	5.2	6.2	23.4	21.1	12.4	9.4	4.1	0.2	12.7	4.0	18.1	12.1	15.9	8.2	4.1
Total current liabilities		$m	3.0	11.0	12.1	30.7	29.8	19.2	16.3	11.4	7.4	20.9	10.5	23.8	20.7	24.9	16.5	10.1
Non-current liabilities																		
	Term Loan A	$m	38.6	38.1	37.5	37.0	36.3	35.7	34.9	34.1	33.7	33.3	32.9	32.4	31.8	31.2	30.6	30.0
	Term Loan B	$m	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Total non-current liabilities		$m	128.5	128.0	127.5	126.9	126.3	125.6	124.9	124.1	123.7	123.3	122.8	122.3	121.8	121.2	120.5	120.0
Total liabilities		$m	131.5	139.0	139.6	157.6	156.1	144.9	141.2	135.5	131.1	144.1	133.3	146.1	142.5	146.1	137.1	130.1
NET ASSET		$m	355.0	355.2	339.8	315.0	301.6	291.4	278.8	267.6	255.0	233.8	223.7	199.9	201.7	199.4	200.6	186.2
EQUITY																		
Issued capital		$m	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0	355.0
Retained earnings / losses		$m	-	0.2	0.6	5.0	8.6	10.2	11.1	8.0	- 4.5	- 2.5	- 3.1	0.1	2.0	4.7	5.8	6.1
Total equity attributable to owners		$m	355.0	355.2	355.6	360.0	363.6	365.2	366.1	363.0	350.5	352.5	351.9	355.1	357.0	359.7	360.8	361.1
Gearing			26%	26%	27%	27%	28%	29%	30%	31%	32%	33%	34%	35%	35%	35%	36%	38%

GENERATOR CASH FLOW STATEMENT	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
CASH FLOWS FROM OPERATING ACTIVITIES															
Receipts from customers	70.9	75.6	141.8	153.4	107.0	93.9	80.7	66.4	119.8	84.3	112.0	129.3	147.5	124.7	86.9
Payments to suppliers	38.3	40.0	55.5	67.3	46.1	46.3	49.7	48.9	67.5	51.8	41.5	72.5	80.5	78.1	53.9
Interest paid	8.0	10.6	10.5	12.3	12.9	12.8	12.7	12.9	10.6	9.9	9.8	9.8	9.7	8.4	7.2
Payment to tax office	0.0	5.2	6.2	23.4	21.1	12.4	9.4	4.1	0.2	12.7	4.0	18.1	12.1	15.9	8.2
Net cashflows provided by operating activities	24.6	19.8	69.5	50.3	27.0	22.4	8.9	0.5	41.5	10.0	56.6	29.0	45.2	22.3	17.6
CASH FLOWS FROM INVESTING ACTIVITIES															
Cash flow from securities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					
Capital expenditure (capex on OCGT)	1.0											15.0	15.0	15.0	
Net cashflows provided by investing activities	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-15.0	-15.0	-15.0	0.0
CASH FLOWS FROM FINANCING ACTIVITIES															
Proceeds from share market	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proceeds from borrowings (Term Loan A)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proceeds from borrowings (Term Loan B)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Loan Redemptions	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.4	0.4	0.5	0.5	0.5	0.6	0.7	0.6
Capital Distrbutions	0.0	15.8	29.2	17.1	11.8	13.5	8.1	0.1	23.2	9.5	27.0	0.0	5.0	0.0	14.6
Dividends	1.4	3.5	39.7	32.6	14.6	8.1	0.0	0.0	17.9	0.0	29.1	16.6	24.5	10.0	2.5
Net cashflows provided by financing activities	-1.9	-19.8	-69.5	-50.3	-27.0	-22.4	-8.9	-0.5	-41.5	-10.0	-56.6	-17.2	-30.2	-10.6	-17.6
Net Cash Flows	21.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-3.2	0.0	-3.3	0.0
Closing Cash	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	38.1	38.1	34.8	34.8

RETAILER	PROFIT & LOSS STATEMENT																
Year Index			2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Resi customer numbers			288,242	293,075	297,328	303,855	308,284	315,290	319,546	325,728	331,513	334,295	339,212	344,311	349,129	355,071	366,829
Swicthing	2% spread		-5,765	-5,862	-5,947	55,558	62,586	67,236	74,426	62,463	53,162	49,670	49,168	50,012	68,280	101,624	80,230
SME customer numbers			41,177	41,868	42,475	43,408	44,041	45,041	45,649	46,533	47,359	47,756	48,459	49,187	49,876	50,724	52,404
Swicthing	3% spread		-824	-837	-850	7,937	8,941	9,605	10,632	8,923	7,595	7,096	7,024	7,145	9,754	14,518	11,461
ANNUAL LOAD																	
Resi load volume	70%	MWh	2,123,077	2,276,417	2,235,587	2,190,871	2,300,891	2,466,815	2,367,754	2,116,235	2,061,719	2,099,461	2,053,365	2,044,798	2,076,127	2,023,708	2,053,646
SME load volume	30%	MWh	909,890	975,607	958,109	938,945	986,096	1,057,206	1,014,752	906,958	883,594	899,769	880,014	876,342	889,769	867,303	880,134
C&I load volume		MWh	1,452,157	1,474,175	1,473,458	1,473,639	1,548,627	1,706,921	1,588,576	1,440,230	1,340,535	1,366,580	1,275,665	1,213,061	1,212,722	1,195,778	1,212,990
Total annual load		MWh	4,485,123	4,726,199	4,667,153	4,603,455	4,835,614	5,230,943	4,971,082	4,463,423	4,285,847	4,365,810	4,209,043	4,134,201	4,178,619	4,086,789	4,146,770
SALES REVENUES																	
Resi		$m	282.4	309.1	298.0	321.0	360.3	423.9	461.2	448.7	493.4	606.8	610.5	575.3	605.6	604.5	594.2
SME		$m	126.1	138.4	139.9	150.5	162.6	199.0	216.2	209.8	190.2	225.8	226.9	214.6	245.5	247.8	236.3
C&I		$m	107.7	113.3	118.4	145.1	158.5	168.4	155.8	152.2	174.8	203.9	182.9	170.2	181.0	194.6	191.7
Total sales		**$m**	516.3	560.8	556.3	616.7	681.4	791.4	833.2	810.7	858.4	1,036.5	1,020.3	960.2	1,032.1	1,046.9	1,022.2
EXPENSES																	
Network (N Resi)		$m	118.9	136.6	145.6	155.1	175.0	201.2	221.7	226.0	252.6	304.6	332.7	310.1	305.3	248.6	237.3
Network (N SME)		$m	45.7	52.8	56.1	59.5	67.4	77.8	85.9	85.6	99.7	122.2	132.4	120.9	124.2	103.0	92.5
Network (N C&I)		$m	36.5	39.9	43.1	46.7	52.9	62.8	67.2	68.0	75.6	92.8	96.0	83.7	84.6	71.0	63.8
Pool purchases		$m	139.5	151.9	270.6	281.5	180.8	204.0	175.2	136.1	312.0	270.6	287.9	281.0	474.9	312.6	356.8
Hedge costs		$m	42.8	42.6	- 71.2	- 2.1	117.1	71.8	58.0	63.7	- 60.1	16.4	- 49.6	- 31.6	- 200.3	42.7	- 3.8
Total Network & Wholesale Costs		$m	383.4	423.8	444.4	540.7	593.2	617.6	608.0	579.4	679.8	806.7	799.5	764.1	788.7	777.8	746.7
Green / Carbon Costs		$m	9.6	11.7	14.0	15.1	17.9	26.1	21.6	37.4	48.6	44.3	34.2	36.1	48.3	61.2	81.1
Ancillary services		$m	1.3	1.4	1.4	1.4	1.9	1.9	1.9	2.0	2.0	1.3	2.0	1.5	1.4	1.4	1.8
NEM fees		$m	1.3	1.4	1.4	1.5	1.5	1.6	1.7	1.7	1.7	1.6	2.0	1.9	2.0	2.2	2.2
Losses		$m	18.1	18.3	18.5	22.6	26.0	26.1	23.4	23.8	22.7	25.8	21.5	19.7	24.1	32.3	31.5
TOTAL G+N Costs		$m	413.9	456.6	479.7	581.3	640.5	673.4	656.6	644.3	754.8	879.6	859.3	823.3	864.6	874.9	863.3
Retail Operating Costs		$m	26.9	32.7	34.0	35.6	37.1	38.8	40.4	42.2	44.0	45.5	47.3	49.2	51.1	53.1	56.2
Customer Acquisition Costs		$m	11.7	12.2	12.6	13.2	13.8	14.4	15.0	15.7	16.3	16.9	17.6	17.9	18.6	19.4	20.5
Other Retail Costs		m$	0.5	0.5	0.5	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total G+N+R		m$	452.9	502.0	526.9	630.7	691.9	727.3	712.6	702.7	815.6	942.6	924.8	890.9	934.9	948.0	940.6
Bad debts	1%	m$	5.2	5.6	5.6	6.2	6.8	7.9	8.3	8.1	8.6	10.4	10.2	9.6	10.3	10.5	10.2
Total Expenses		**m$**	458.1	507.6	532.4	636.9	698.8	735.2	720.9	710.8	824.2	952.9	935.0	900.5	945.2	958.4	950.8
EBITDA		**m$**	58.2	53.2	23.9	-20.2	-17.4	56.1	112.3	99.9	34.2	83.6	85.3	59.6	86.9	88.5	71.4
Depreciation and amortisation		m$	8.7	9.1	9.6	9.8	10.2	6.1	6.2	6.2	6.3	6.4	6.5	6.5	6.6	6.7	6.7
EBIT			49.5	44.1	14.3	-29.9	-27.6	50.1	106.1	93.6	27.9	77.2	78.8	53.1	80.4	81.8	64.7
Financing costs		m$	11.8	11.8	11.7	13.5	16.7	20.8	25.8	27.2	24.6	24.4	24.1	23.8	23.5	21.9	17.3
Taxation			11.3	9.7	0.8	0.0	0.0	9.0	24.1	19.9	1.0	15.8	16.4	8.8	17.0	18.0	14.2
NPAT		**m$**	26.3	22.6	1.8	-43.4	-44.2	20.3	56.2	46.5	2.3	36.9	38.3	20.5	39.8	41.9	33.2
FFO		**m$**	33.1	29.7	9.3	-35.9	-36.3	24.0	59.9	50.3	6.1	40.7	42.1	24.3	43.6	45.8	37.0
FFO/I		**FFO/I**	3.8	3.5	1.8	-1.7	-1.2	2.2	3.3	2.8	1.2	2.7	2.7	2.0	2.9	3.1	3.1
Distribution																	
Dvidend	90%		23.7	20.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.5	18.4	35.8	37.8	29.8
Retained earnings			2.63	2.26	1.83	-43.44	-44.24	20.26	56.22	46.49	2.28	36.95	3.83	2.05	3.98	4.19	3.32
Economic Returns			9.9%	8.9%	2.8%	-10.4%	-12.1%	9.9%	22.3%	15.6%	1.9%	11.1%	10.4%	6.1%	10.7%	11.1%	8.9%

RETAILER BALANCE SHEET																	
Year Index		**Open**	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ASSETS																	
Current asset																	
Cash and cash equivale	$m	137.4	132.6	130.8	94.7	109.0	112.6	186.0	232.4	232.4	232.1	284.0	240.6	236.5	205.2	233.2	233.6
Trade receivables	$m	106.3	109.6	119.7	119.7	117.7	127.8	142.0	167.4	179.8	174.4	182.9	222.1	221.5	208.2	224.7	226.2
Market Prudential Deposits	$m	0.0	25.9	27.3	64.1	63.2	66.4	71.8	68.2	61.3	58.8	59.9	65.8	64.6	124.7	121.9	123.7
Total current asset	$m	243.7	268.1	277.8	278.5	289.9	306.8	399.8	468.1	473.5	465.4	526.9	528.5	522.6	538.1	579.8	583.4
Non-current asset																	
Retail assets	$m	93.0	86.3	79.2	71.8	64.2	56.3	52.6	48.9	45.1	41.3	37.5	33.7	29.9	26.0	22.1	18.2
Goodwill	$m	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7
Total non-current asset	$m	265.7	259.0	251.9	244.5	236.9	229.0	225.3	221.6	217.8	214.0	210.2	206.4	202.6	198.7	194.8	191.0
Total asset	$m	509.5	527.0	529.7	522.9	526.9	535.8	625.1	689.7	691.3	679.4	737.2	734.9	725.2	736.8	774.7	774.4
LIABILITIES																	
Current liability																	
Trade payables	$m	31.4	33.1	36.1	37.4	47.9	52.0	51.7	48.2	44.8	52.7	61.4	57.8	56.9	59.7	65.5	64.3
Interests payables	$m	-	2.9	2.9	2.9	3.3	4.1	5.1	6.4	6.7	6.1	6.0	5.9	5.9	5.8	5.4	4.3
Provision - Taxes	$m	-	11.3	9.7	0.8	-	-	9.0	24.1	19.9	1.0	15.8	16.4	8.8	17.0	18.0	14.2
Total current liabilities	$m	31.4	47.3	48.7	41.1	51.2	56.1	65.9	78.7	71.4	59.7	83.3	80.1	71.5	82.6	88.9	82.7
Non-current liabilities																	
Term Loan A	$m	71.3	70.4	69.4	68.4	105.7	154.0	213.2	208.8	206.4	203.9	201.2	198.2	195.0	191.6	219.0	221.5
Term Loan B	$m	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3	71.3
Deferred tax liabilities	$m																
Total non-current liabilities	$m	142.6	141.7	140.8	139.7	177.0	225.3	284.5	280.1	277.7	275.2	272.5	269.5	266.4	262.9	290.3	292.9
Total liabilities	$m	174.1	189.0	189.4	180.8	228.2	281.4	350.4	358.8	349.2	334.9	355.7	349.7	337.9	345.5	379.2	375.6
NET ASSET	$m	335.4	338.0	340.3	342.1	298.7	254.4	274.7	330.9	342.2	344.5	381.4	385.2	387.3	391.3	395.5	398.8
EQUITY																	
Issued capital	$m	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4	335.4
Retained earnings / losses	$m	-	2.6	4.9	6.7	-36.7	-80.9	-60.7	-4.5	42.0	44.3	81.3	85.1	87.1	91.1	95.3	98.6
Total equity attributable to owners	$m	335.4	338.0	340.3	342.1	298.7	254.4	274.7	330.9	377.4	379.7	416.6	420.5	422.5	426.5	430.7	434.0
Gearing		28%	27%	27%	27%	34%	42%	46%	41%	40%	41%	37%	37%	37%	36%	37%	38%

RETAILER	CASH FLOW STATEMENT														
Year Index	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
CASH FLOWS FROM OPERATING ACTIVITIES															
Receipts from customers	487.1	549.3	519.5	619.5	668.1	771.8	811.3	805.3	866.3	1026.9	975.3	961.9	985.4	1033.1	1019.0
Payments to suppliers	456.5	504.6	531.1	626.4	694.7	735.4	724.5	714.3	816.3	944.2	938.6	901.4	942.3	952.7	952.0
Interest paid	8.9	11.8	11.7	13.1	15.9	19.8	24.6	26.9	25.2	24.4	24.2	23.9	23.6	22.3	18.4
Payment to tax office	0.0	11.3	9.7	0.8	0.0	0.0	9.0	24.1	19.9	1.0	15.8	16.4	8.8	17.0	18.0
Net cashflows provided by operating activities	21.7	21.7	-33.0	-20.8	-42.5	16.6	53.3	40.0	4.8	57.2	-3.4	20.1	10.7	41.1	30.6
CASH FLOWS FROM INVESTING ACTIVITIES															
Cash flow from securities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Payments for assets acquired	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital expenditure (capex on OCGT)	2.0	2.1	2.1	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8
Net cashflows provided by investing activities	-2.0	-2.1	-2.1	-2.2	-2.3	-2.4	-2.4	-2.5	-2.5	-2.6	-2.6	-2.7	-2.7	-2.8	-2.8
CASH FLOWS FROM FINANCING ACTIVITIES															
Proceeds from share market	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proceeds from borrowings (Term Loan A)	0.0	0.0	0.0	38.4	50.2	62.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.1	6.5
Proceeds from borrowings (Term Loan B)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Loan Redemptions	0.9	1.0	1.0	1.1	1.9	2.9	4.4	2.3	2.5	2.7	2.9	3.2	3.4	3.7	3.9
Return of Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dividend paid	23.7	20.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.5	18.4	35.8	37.8	29.8
Net cashflows provided by financing activities	-24.6	-21.3	-1.0	37.3	48.3	59.2	-4.4	-37.5	-2.5	-2.7	-37.4	-21.6	-39.2	-10.4	-27.3
Net Cash Flows	-4.9	-1.7	-36.1	14.3	3.5	73.4	46.4	0.0	-0.3	51.9	-43.4	-4.1	-31.3	27.9	0.4
Closing Cash	132.6	130.8	94.7	109.0	112.6	186.0	232.4	232.4	232.1	284.0	240.6	236.5	205.2	233.2	233.6

VERTICAL INTEGRATION PROFIT & LOSS																	
Year Index			2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ANNUAL LOAD																	
Resi load volume		MWh	2,123	2,276	2,236	2,191	2,301	2,467	2,368	2,116	2,062	2,099	2,053	2,045	2,076	2,024	2,054
SME load volume		MWh	910	976	958	939	986	1,057	1,015	907	884	900	880	876	890	867	880
C&I load volume		MWh	1,452	1,474	1,473	1,474	1,549	1,707	1,589	1,440	1,341	1,367	1,276	1,213	1,213	1,196	1,213
Generation		MWh	-926	-932	-1,339	-1,551	-927	-951	-990	-951	-1,058	-712	-1,619	-1,286	-730	-858	-401
Total annual load		MWh	3,560	3,795	3,328	3,052	3,909	4,280	3,981	3,512	3,228	3,653	2,590	2,849	3,449	3,229	3,746
SALES REVENUE																	
Resi		$m	282.4	309.1	298.0	321.0	360.3	423.9	461.2	448.7	493.4	606.8	610.5	575.3	605.6	604.5	594.2
SME		$m	126.1	138.4	139.9	150.5	162.6	199.0	216.2	209.8	190.2	225.8	226.9	214.6	245.5	247.8	236.3
C&I		$m	107.7	113.3	118.4	145.1	158.5	168.4	155.8	152.2	174.8	203.9	182.9	170.2	181.0	194.6	191.7
Excess Generation Spot Sales		$m	0.6	0.2	2.3	1.8	0.4	0.1	0.2	0.8	3.3	1.2	4.3	6.5	4.2	6.8	1.5
Excess Generation Cap Sales		$m	6.4	3.4	-3.5	2.2	2.2	1.7	3.3	6.3	1.0	2.4	0.0	3.3	4.4	7.4	2.5
Total sales		**$m**	523.3	564.3	555.1	620.7	684.0	793.2	836.8	817.8	862.8	1,040.1	1,024.5	969.9	1,040.7	1,061.2	1,026.2
EXPENSES																	
Fuel		$m	30.4	31.9	47.0	57.3	34.9	37.0	40.0	38.7	43.9	30.5	27.4	63.1	70.8	67.0	42.6
O&M		$m	8.0	8.3	9.8	11.0	9.2	9.6	10.0	10.0	10.6	9.6	13.4	12.2	10.2	10.9	9.1
Network (N Resi)		$m	118.9	136.6	145.6	155.1	175.0	201.2	221.7	226.0	252.6	304.6	332.7	310.1	305.3	248.6	237.3
Network (N SME)		$m	45.7	52.8	56.1	59.5	67.4	77.8	85.9	85.6	99.7	122.2	132.4	120.9	124.2	103.0	92.5
Network (N C&I)		$m	36.5	39.9	43.1	46.7	52.9	62.8	67.2	68.0	75.6	92.8	96.0	83.7	84.6	71.0	63.8
Net Pool Purchases		$m	85.3	87.5	122.0	130.4	118.7	129.3	111.4	96.7	191.9	200.9	138.2	160.6	305.3	231.7	302.4
Hedge Costs		$m	18.9	27.7	-64.4	-8.2	62.8	46.4	35.2	32.4	-52.7	2.3	-8.1	-32.5	-152.4	1.9	-34.7
Total Network & Wholesale Costs		$m	343.9	384.7	359.4	451.9	521.0	564.1	571.4	557.5	621.7	763.0	732.1	718.2	748.0	734.1	713.2
Green costs		$m	9.6	11.7	14.0	15.1	17.9	26.1	21.6	37.4	48.6	44.3	34.2	36.1	48.3	61.2	81.1
Carbon Costs	$23	$m	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.6	10.0	0.0	0.0	0.0	0.0	0.0
Ancillary services		$m	1.3	1.4	1.4	1.4	1.9	1.9	1.9	2.0	2.0	1.3	2.0	1.5	1.4	1.4	1.8
NEM fees		$m	1.3	1.4	1.4	1.5	1.5	1.6	1.7	1.7	1.7	1.6	2.0	1.9	2.0	2.2	2.2
Losses		$m	18.1	18.3	18.5	22.6	26.0	26.1	23.4	23.8	22.7	25.8	21.5	19.7	24.1	32.3	31.5
TOTAL G+N Costs		$m	374.3	417.5	394.7	492.4	568.3	619.8	620.0	622.4	711.2	846.0	791.8	777.3	823.8	831.1	829.8
Retail Operating Costs		$m	26.9	32.7	34.0	35.6	37.1	38.8	40.4	42.2	44.0	45.5	47.3	49.2	51.1	53.1	56.2
Customer Acquisition Costs		$m	11.7	12.2	12.6	13.2	13.8	14.4	15.0	15.7	16.3	16.9	17.6	17.9	18.6	19.4	20.5
Other Retail Costs		m$	0.5	0.5	0.5	0.6	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total G+N+R		m$	413.4	462.9	441.9	541.8	619.8	673.7	676.0	680.9	772.1	908.9	857.3	845.0	894.1	904.2	907.1
Bad debts	1%	m$	5.2	5.6	5.6	6.2	6.8	7.9	8.3	8.1	8.6	10.4	10.2	9.6	10.3	10.5	10.2
Total Expenses		**m$**	418.6	468.5	447.5	548.0	626.6	681.7	684.3	689.0	780.7	919.3	867.5	854.6	904.4	914.7	917.3
EBITDA		**m$**	104.8	95.8	107.6	72.7	57.4	111.5	152.5	128.8	82.0	120.8	157.1	115.3	136.3	146.5	108.8
Depreciation and amortisation		m$	24.0	24.5	24.9	25.1	25.5	21.4	21.5	21.6	21.7	21.7	21.8	21.9	22.4	23.0	23.6
EBIT			80.7	71.4	82.7	47.6	31.8	90.1	131.0	107.2	60.4	99.1	135.3	93.4	113.8	123.5	85.3
Financing costs		m$	17.1	16.9	16.8	20.2	20.1	19.9	19.7	20.5	15.9	15.7	15.6	15.4	15.3	12.6	11.1
Taxation			19.1	16.3	19.8	8.2	3.5	21.1	33.4	26.0	13.4	25.0	35.9	23.4	29.6	33.3	22.3
NPAT		**m$**	44.55	38.10	46.16	19.14	8.24	49.16	77.89	60.71	31.17	58.37	83.77	54.61	69.00	77.64	51.93
FFO		**m$**	65.6	60.5	68.9	42.0	31.5	68.2	96.9	79.8	50.3	77.5	102.9	58.8	73.7	82.8	72.6
FFO/I			4.8	4.6	5.1	3.1	2.6	4.4	5.9	4.9	4.2	5.9	7.6	4.8	5.8	7.6	7.5
Distributions																	
Dvidends	90%	$m	40.1	34.3	41.5	17.2	7.4	44.2	70.1	54.6	28.1	52.5	75.4	49.1	62.1	69.9	46.7
Retained earnings		$m	4.5	3.8	4.6	1.9	0.8	4.9	7.8	6.1	3.1	5.8	8.4	5.5	6.9	7.8	5.2
Economic Returns			9.2%	8.3%	9.5%	5.6%	4.1%	9.4%	13.4%	10.8%	6.7%	10.4%	13.8%	9.7%	11.6%	12.7%	9.3%

VERTICAL INTEGRATION	BALANCE SHEET																
YEAR		Open	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
ASSETS																	
Current asset																	
Cash and cash equivalents	$m	157.0	198.0	198.0	198.0	198.0	198.0	198.0	207.4	208.9	217.8	251.2	240.3	236.4	264.2	262.7	263.1
Trade receivables	$m	114.2	117.8	128.4	137.0	135.4	139.5	152.7	176.5	187.3	189.0	192.0	235.4	236.6	225.4	238.7	235.6
Market Prudential Deposits	$m	0.0	3.8	4.0	4.8	6.7	7.0	7.6	7.2	6.5	13.2	18.5	17.9	17.6	19.0	26.9	36.0
Total current asset	$m	271.3	319.6	330.4	339.7	340.0	344.4	358.2	391.1	402.7	420.0	461.7	493.6	490.5	508.6	528.3	534.7
Non-current asset																	
Retail assets	$m	93.0	86.3	79.2	71.8	64.2	56.3	52.6	48.9	45.1	41.3	37.5	33.7	29.9	26.0	22.1	18.2
Generation Plant	$m	459.0	444.7	429.4	414.0	398.7	383.4	368.0	352.7	337.4	322.0	306.7	291.4	291.0	290.2	288.9	272.0
Goodwill	$m	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7	172.7
Total non-current asset	$m	724.7	703.7	681.3	658.5	635.6	612.4	593.3	574.3	555.2	536.1	516.9	497.8	493.6	488.9	483.7	463.0
Total asset	$m	996.0	1,023.3	1,011.7	998.2	975.7	956.8	951.5	965.4	957.9	956.0	978.7	991.4	984.1	997.5	1,012.0	997.7
LIABILITIES																	
Current liability	$m																
Trade payables	$m	34.4	36.3	39.4	42.1	53.5	55.6	55.6	52.3	48.8	58.4	65.5	61.1	63.1	66.4	71.9	68.5
Interests payables+Loans	$m	-	4.2	4.2	5.0	5.0	5.0	4.9	4.9	3.9	3.9	3.9	3.8	3.8	3.1	3.1	1.5
Provision - Taxes	$m	-	19.1	16.3	19.8	8.2	3.5	21.1	33.4	26.0	13.4	25.0	35.9	23.4	29.6	33.3	22.3
Total current liabilities	$m	34.4	59.6	59.9	66.9	66.7	64.1	81.5	90.6	78.8	75.6	94.4	100.9	90.3	99.1	108.3	92.3
Non-current liabilities																	
Term Loan A	$m	135.6	133.3	130.9	128.4	125.7	123.0	120.1	117.1	115.4	113.5	111.5	109.5	107.3	105.0	152.6	174.0
Term Loan B	$m	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6	135.6
Deferred tax liabilities	$m																
Total non-current liabilities	$m	271.2	268.9	266.5	263.9	261.3	258.6	255.7	252.7	251.0	249.1	247.1	245.1	242.9	240.6	288.2	309.5
Total liabilities	$m	305.6	328.4	326.3	330.8	328.0	322.6	337.2	343.3	329.7	324.7	341.6	345.9	333.2	339.7	396.4	401.8
NET ASSET	$m	690.4	694.8	685.4	667.3	647.7	634.2	614.3	622.1	628.2	631.3	637.1	645.5	651.0	657.9	615.6	595.8
EQUITY																	
Issued capital	$m	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4	690.4
Retained earnings / losses	$m	-	4.5	8.3	12.9	14.8	15.6	20.5	28.3	34.4	37.5	43.3	51.7	57.2	64.1	71.9	77.0
Total equity attributable to owners	$m	690.4	694.8	698.7	703.3	705.2	706.0	710.9	718.7	724.8	727.9	733.7	742.1	747.6	754.5	762.2	767.4
Gearing		27%	26%	26%	26%	27%	27%	27%	26%	26%	26%	25%	25%	25%	24%	28%	31%

VERTICAL INTEGRATION CASH FLOW STATEMENT															
Year Index	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
CASH FLOWS FROM OPERATING ACTIVITIES															
Receipts from customers	515.9	553.5	545.9	620.3	679.6	779.4	813.3	807.8	854.3	1,031.8	981.8	969.0	1,050.4	1,039.9	1,020.2
Payments to suppliers	416.8	465.4	444.8	536.6	624.5	681.7	687.6	692.5	771.1	912.1	871.9	852.6	901.1	909.2	920.7
Interest paid	12.9	17.0	15.9	20.3	20.1	19.9	19.8	21.4	15.9	15.8	15.6	15.5	15.9	12.6	12.7
Payment to tax office	0.0	19.1	16.3	19.8	8.2	3.5	21.1	33.4	26.0	13.4	25.0	35.9	23.4	29.6	33.3
Net cashflows provided by operating activities	86.3	52.0	68.9	43.6	26.8	74.3	84.9	60.4	41.3	90.5	69.2	65.1	110.0	88.6	53.6
CASH FLOWS FROM INVESTING ACTIVITIES															
Cash flow from securities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					
Capital expenditure (capex on OCGT)	3.0	2.1	2.1	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.6	17.7	17.7	17.8	2.8
Net cashflows provided by investing activities	-3.0	-2.1	-2.1	-2.2	-2.3	-2.4	-2.4	-2.5	-2.5	-2.6	-2.6	-17.7	-17.7	-17.8	-2.8
CASH FLOWS FROM FINANCING ACTIVITIES															
Proceeds from share market	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proceeds from borrowings (Term Loan A)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	25.0
Proceeds from borrowings (Term Loan B)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Loan Redemptions	2.3	2.4	2.5	2.6	2.7	2.9	3.0	1.8	1.9	2.0	2.1	2.2	2.3	2.4	3.6
Capital Returns	0.0	13.3	22.7	21.5	14.3	24.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	25.0
Dividends	40.1	34.3	41.5	17.2	7.4	44.2	70.1	54.6	28.1	52.5	75.4	49.1	62.1	69.9	46.7
Net cashflows provided by financing activities	-42.4	-50.0	-66.7	-41.4	-24.5	-71.9	-73.1	-56.4	-29.9	-54.5	-77.5	-51.3	-64.4	-72.3	-50.4
Net Cash Flows	40.9	0.0	0.0	0.0	0.0	0.0	9.4	1.6	8.8	33.4	-10.9	-3.9	27.8	-1.5	0.4
Closing Cash	198.0	198.0	198.0	198.0	198.0	198.0	207.4	208.9	217.8	251.2	240.3	236.4	264.2	262.7	263.1